# NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #23-4

October 11, 2023, 10:00 a.m. – 3:00 p.m. EDT **Hybrid Meeting**
Utility Services Office
93 Pilgrim Park Rd, Suite A
Waterbury, VT 05676
Attire: Business Casual

**Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)**
**Guest Code: 24455030828**
**Password: KJmNpFY7@22 (55667397 from phone)**
**WebEx Link**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 8, 2023
NPCC Glossary of Terms, dated August 10, 2021

**Introductions, Safety Message and Chair's Remarks**

**NPCC Antitrust Compliance Guidelines**

**Agenda Items:**

**1.0 Meeting Agenda**

**2.0 RSC Meeting Minutes (Approval Item)**

**3.0 Items Requiring RSC Discussion/Endorsement**

- 3.1 FERC Activities
- 3.2 PRC-006-NPCC-3 Status
- 3.3 RSC Scope of Work and Work Plan
- 3.4 RSC Vice Chair Election
- 3.5 NPCC Corporate Goal II-2 Incorporate Provisions of IEEE-2800 into NPCC Criteria
- 3.6 NERC Project Updates by Latrice Harkness (12:30 PM)

**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<br>Norm Dang from IESO @ 12:45 PM | 11/16/23 (F) | 11/16/23 (A) |

| | | |
|---|---|---|
| Project 2017-01 Modifications to BAL-003-1.1<br>David Lemmons from Greybeard Compliance Services @ 1:15 PM | 6/1/23<br>(F) | 6/1/23<br>(A) |
| Project 2019-04 Modifications to PRC-005-6<br>Giuseppe Giannuzzi from HQ @ 1:30 PM NC | 7/24/23<br>(F) | 7/24/23<br>(I) |
| Project 2020-04 Modifications to CIP-012<br>Joe Gatten from Xcel Energy @ 2:30 PM | 11/2/23<br>(F) | 11/2/23<br>(A) |
| Project 2020-06 Verifications of Models and Data for Generators<br>Chris Larson from NERC @ 1:45 PM | 10/24/23<br>(F) | 7/21/23<br>(A) |
| Project 2021-01 Modifications to MOD-025 and PRC-019<br>Chris Larson from NERC @ 1:45 PM | 6/8/23<br>(F) | 6/8/23<br>(A) |
| Project 2021-02 Modifications to VAR-002<br>Adrian Raducea from DTE Energy and David Daniels from AEP @ 2:00 PM | 11/6/23<br>(F) | 11/6/23<br>(A) |
| Project 2021-03 CIP-002 Transmission Owner Control Centers<br>Dominique Love from NERC @ 2:45 PM NC | 11/9/23<br>(F) | 11/9/23<br>(I) |
| Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination<br>NERC Legal and HQ SME @ 1:00 PM | 9/16/23<br>(F) | 10/6/23<br>(F) |
| Project 2021-08 Modifications to FAC-008<br>Ben Wu from NERC @ 3:00 PM | 10/19/23<br>(F) | 10/19/23<br>(I) |
| Project 2022-01 Reporting ACE Definition and Associated Terms<br>Ruida Shu | 10/30/23<br>(F) | 10/30/23<br>(I) |
| Project 2022-02 Modifications to TPL-001 and MOD-032<br>Ben Wu from NERC @ 3:00 PM | 7/14/23<br>(F) | 7/14/23<br>(I) |
| Project 2023-01 EOP-004 IBR Event Reporting<br>Chris Larson from NERC @ 1:45 PM | 9/11/23<br>(F) | 9/11/23<br>(I) |
| **Comments:** (I) – Informal; (F) – Formal; (N) – Nomination Period<br>**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

## 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 25th – Call | February 22nd – Call | March 22nd – SPP |
| April 19th – Call | May 17th – Call | June 21st – Call |
| July 19th – MRO | August 23rd – Call | September 20th – NERC |
| October 18th – Call | November 15th – Call | December 13th – NERC |

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

| | | |
|---|---|---|
| February 15-16 – Tuscan, AZ | May 3-4 – Hybrid Schedule | August 15-17 – Ottawa, ON |
| December TBD - 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 2023 State of Reliability Report
Report (nerc.com)

**10.0 Future RSC Meetings and Conference Calls**

10.1 RSC 2023 Meeting Dates

| |
|---|
| February 22nd - WebEx |
| May 24-25th – NYISO and WebEx |

| |
|---|
| August 9-10th – WebEx |
| October 11-12th – Utility Services and WebEx |
| December 7th - General Meeting and WebEx |

**Northeast Power Coordinating Council, Inc. (NPCC)**

**Antitrust Compliance Guidelines**

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

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

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

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's General Counsel and Corporate Secretary, Mr. Damase Hebert at (646) 737-2335 or dhebert@npcc.org.

# NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #23-3

August 9, 2023, 10:00 a.m. – 3:00 p.m. EDT **WebEx Meeting**

**Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)**
**Guest Code: 24304049507**
**Password: Zi3qgkJS9?8 (94374557 from phone)**
**WebEx Link**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated March 8, 2023
NPCC Glossary of Terms, dated August 10, 2021

**Attendance:**

| | Name | Organization | Sector(s) | Status |
|---|---|---|---|---|
| 1. | Gerry Dunbar | Northeast Power Coordinating Council | | WebEx |
| 2. | Ruida Shu | Northeast Power Coordinating Council | | WebEx |
| 3. | Brian Deckert | Northeast Power Coordinating Council | | WebEx |
| 4. | Kal Ayoub | FERC | Guest | WebEx |
| 5. | Abbas Munir | Bruce Power | 4 | WebEx |
| 6. | Bendong Sun | Bruce Power | 4 | WebEx |
| 7. | Chantal Mazza | Hydro Quebec | 2 | WebEx |
| 8. | Constantin Chitescu | OPG | 4 | WebEx |
| 9. | Dave Kwan | OPG | 4 | WebEx |
| 10. | Doug Preston | OPG | 4 | WebEx |
| 11. | Erin Wilson | NB Power | 1 | WebEx |
| 12. | Harish Vijay Kumar | IESO | 2 | WebEx |
| 13. | Herb Schrayshuen | Power Advisors, LLC | Guest | WebEx |
| 14. | Jason Chandler | Con Edison | 5 | WebEx |
| 15. | Jeffrey Streifling | NP Power | 1 | WebEx |
| 16. | Joel Charlebois | AESI | 7 | WebEx |
| 17. | Jim Grant | NYISO | 2 | WebEx |
| 18. | Joshua London | Eversource | 1 | WebEx |
| 19. | Kevin Mei | Orange and Rockland | Guest | WebEx |
| 20. | Michael Courchesne | ISO-NE | 2 | WebEx |
| 21. | Michael Jones | National Grid | 3 | WebEx |

| | | | | |
|---|---|---|---|---|
| 22. | Michael Ridolfino | CHG&E | 1 | WebEx |
| 23. | Mike Foley | Con Edison | 4 | WebEx |
| 24. | Parada Mitchell, Silvia | NextEra | 4 | WebEx |
| 25. | Randy Buswell | VELCO | 1 | WebEx |
| 26. | Sean Bodkin | Dominion | 4 | WebEx |
| 27. | Shivaz Chopra | NYPA | 6 | WebEx |
| 28. | Stephanie Ullah-Mazzuca | Orange and Rockland | 1 | WebEx |
| 29. | Tim Kucey | PSEG | 4 | WebEx |
| 30. | Tobi Ajayi | OPG | Guest | WebEx |
| 31. | Tracy MacNicoll | Utility Services | 5 | WebEx |
| 32. | Wes Yeomans | NY State Reliability Council | 7 | Phone |
| 33. | Vijay Puran | NY State Department of Public Service | 6 | WebEx |
| 34. | Norm Dang | IESO | Guest | WebEx |
| 35. | David Lemmons | Greybeard Compliance | Guest | WebEx |
| 36. | Joe Gatten | Xcel Energy | Guest | WebEx |
| 37. | Chris Larson | NERC | Guest | WebEx |
| 38. | Adrain Raducea | DTE Energy | Guest | WebEx |
| 39. | Russell Noble | Cowlitz PUD | Guest | WebEx |
| 40. | Matthew Harward | SPP | Guest | WebEx |
| 41. | Ben Wu | NERC | Guest | WebEx |

**Introductions, Safety Message and Chair's Remarks**

Gerry Dunbar provided remarks on standards activities. Gerry gave an update on the Congressional mandated Regional Transfer Capability study, spoke on how NERC will be looking for more funding for the study and staffing. Also gave an update on new offices, moved from 10th to 4th floor.

Ruida Shu gave safety message, used the '10 items hidden in the picture.'

Kal Ayoub presented update on winter storm Elliot and Order 896

**NPCC Antitrust Compliance Guidelines**

The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

**Agenda Items:**

**1.0 <u>Meeting Agenda</u>**

**2.0 <u>RSC Meeting Minutes (Approval Item)</u>**

Approval of the May 24, 2023, RSC meeting minutes – minor change was made to the draft RSC meeting minutes that were provided in the agenda package.

Sean Bodkin made the motion to approve the RSC meeting minutes.
Mike Jones seconded the motion.
The May 24, 2023, RSC meeting minutes is approved.

## 3.0 Items Requiring RSC Discussion/Endorsement

### 3.1 FERC Activities

Kal updated the RSC members on FERC and NERC Joint Inquiry, FERC Orders, and Technical Conferences.

June 2023, joint status update on winter storm Elliot.

Winterization of Natural Gas units and infrastructure

Grid operator preparedness

Order 896

Corrective Action Plan must be developed.

NERC directed to develop new or modify standards to address 3 major concerns.

- Benchmark events (extreme weather)
- Must require planning entities to have extreme weather plans that include mixed resources.
- Must have corrective actions for examples of when there were failures during extreme weather.

Order 897

- One-time informational report describing how transmission providers plan for extreme weather events.
    - Establish scope.
    - Develop inputs.
    - Identify vulnerabilities.
    - Identify cost.
    - Identify corrective actions.
- Also asked for clarification on how transmission providers define extreme weather.

October 23, 2023, is the deadline.

FERC Technical Conferences

November 9, 2023, Reliability Technical Conference lead by FERC.

### 3.2 PRC-006-NPCC-3 RSAR (Approval)

Constantine made the motion to accept the PRC-006-NPCC-3 RSAR.
Jim Grant seconded the motion.
Motion carried.
Next Step: Send it to the RCC for assigning Task Force.

### 3.3 October 11-12, 2023, RSC Meeting Location

Ruida Shu discussed the potential meeting locations for October 11-12, 2023, RSC meeting with the RSC members.

3.4 NPCC IT Portal Update

Faisal Nahian presented a walkthrough on some of the features of the portal, including the directory and how to filter through the contacts list.
Also explained how sign on will work
Public facing website sign in button will be retired by end of Q3.

3.5 2003 Black Out Video

3.6 NPCC 2023 Corporate Reliability Goal II-2 – IEEE 2800

Gerry gave an update; end product will be a report that discusses the potential to update IEEE 2800. Once the report is finalized, it will be sent out for a 20-day comment period, probably late August or early September.

## 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 |
|---|---|---|
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| Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination<br>Matthew Harward from SPP @ 2:45 PM | 7/20/23<br>(F) | 7/20/23<br>(I) |
| Project 2021-08 Modifications to FAC-008<br>Ben Wu from NERC @ 12:45 PM | 1/27/22<br>(F) | |
| Project 2022-01 Reporting ACE Definition and Associated Terms<br>Ruida Shu | 3/16/23<br>(F) | 3/16/23<br>(I) |
| Project 2022-02 Modifications to TPL-001 and MOD-032 | 7/14/23 | 7/14/23 |

| | | |
|---|---|---|
| Ben Wu from NERC @ 12:45 PM | (F) | (I) |
| Project 2023-01 EOP-004 IBR Event Reporting<br>Chris Larson from NERC @ 2:00 PM | 9/11/23<br>(F) | 9/11/23<br>(I) |
| **Comments:** (I) – Informal; (F) – Formal; (N) – Nomination Period<br>**Ballots:** (I) – Initial; (A) – Additional; (F) – Final | | |

Project 2019-04 Modifications to PRC-005-6:
The project was posted for a 45-day comment period and initial ballot period which concluded on July 24, 2023. The ballot did not pass. Ballot Result: 35.33% approval for PRC-005-7 and 41.52% approval for Implementation Plan. The SDT schedule their next meeting on August 17, 2023, to review the industry comments received during the comment period.

Project 2022-01 Reporting ACE Definition and Associated Terms:
The SDT has made significant revisions to the Reporting ACE and IIM definitions and will require an additional ballot. In addition, the team drafted the new ADI definition which will require an initial ballot to be posted. The other 24 definitions either had extremely minor or no further revisions were made and will only require a final ballot once the other definitions catch up. It is expected that the new ADI definition will be going to the Standards Committee for initial ballot approval in July. The Reporting ACE and IIM definitions that had significant revisions since it contained the new ADI term will be going out for an additional ballot as well. Once those ballots are over then all 27 definition changes are expected to be ready for final ballot this fall.

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

4.3 Comment Form History (Since last RSC Meeting)
Ruida Shu reviewed the comment form history document in the meeting.

## 5.0 NPCC Non-Standards

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

5.1 Items for Discussion

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

Directory #1 posted for comment on 9/28. Comment period concludes on 11/13.

5.1.2 Directory #7 Remedial Action Schemes (RAS review form).

RAS Review Form developed by TFCP to ensure consistent reporting and facilitate efficient review of new, modified or retired RAS.

Hyperlink to RAS Review form embedded in Directory 7 Appendix B.

## 6.0 RSC Member Items of Interest

6.1 RSC Roster

## 7.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

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7.5 FERC Open Meeting Summaries

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| | | |
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## 9.0 NERC Items of Interest (Since last RSC Meeting)

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

9.2 Alerts
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https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx

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

9.6 2023 State of Reliability Report
Report (nerc.com)

## 10.0 Future RSC Meetings and Conference Calls

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| |
|---|
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- Costs, discounts, terms of sale, profit margins or anything else that might affect prices;
- The resale prices their customers should charge for products they sell them;
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# Nomination Form for "PRC-006-NPCC-3", Automatic Underfrequency Load Shedding Program, Standard Drafting Team (Project Number)

Please return this form to npccstandard@npcc.org by **November 6, 2023,** with the name of the RSAR or Standard Drafting Team in the subject line. If you have any questions, please contact Ruida Shu at rshu@npcc.org , or by telephone at 917-934-7976.

**All candidates' qualifications will be reviewed and participation on a drafting team is subject to the approval by the NPCC Regional Standards Committee, RSC. Applicants are expected to be prepared to participate actively at the drafting team meetings.**

| | | |
|---|---|---|
| Name:<br><br>Organization:<br><br>Address:<br><br>Office Telephone:<br><br>E-mail: | | |
| **Please briefly describe your experience and qualifications to serve on the [Name of RSAR or Standard] Drafting Team.** | | |
| **I represent the following NERC Reliability Region(s) (check all that apply):** | **I represent the following NPCC Bylaw Defined Industry Sectors (check one):** | |
| ☐ ERCOT<br>☐ FRCC | ☐ | 1 — Transmission Owners |
| | ☐ | 2 — Reliability Coordinators |

| | | |
|---|---|---|
| ☐ MRO<br>☐ NPCC<br>☐ RFC<br>☐ SERC<br>☐ SPP<br>☐ WECC<br>☐ NA – Not Applicable | ☐ | 3 — TDUs, Distribution Companies and Load Serving Entities |
| | ☐ | 4 — Generator Owners |
| | ☐ | 5 — Marketers, Brokers and Aggregators |
| | ☐ | 6 — Customers |
| | ☐ | 7 — State, and Provincial Regulatory or other Governmental Authorities |
| | ☐ | 8 — Sub-Regional Reliability Councils, other Regional Entities and Interested Parties |

**Which of the following Function(s)[1] do you have expertise or responsibilities:**

| | |
|---|---|
| ☐ Balancing Authority | ☐ Planning Coordinator |
| ☐ Compliance Monitor | ☐ Transmission Operator |
| ☐ Distribution Provider | ☐ Transmission Owner |
| ☐ Generator Operator | ☐ Transmission Planner |
| ☐ Generator Owner | ☐ Transmission Service Provider |
| ☐ Interchange Authority | ☐ Purchasing-selling Entity |
| ☐ Load-serving Entity | ☐ Resource Planner |
| ☐ Market Operator | ☐ Reliability Coordinator |

**Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.**

| | |
|---|---|
| Name: | Office Telephone: |
| Organization: | E-mail: |
| Name: | Office Telephone: |
| Organization: | E-mail: |

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

*NPCC Board of Director Meeting*
*January xx,2023*
*Draft for Approval, Agenda Item XX*

# 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.

**<u>NPCC Regional Standards Committee Program Responsibilities (related to Criteria and Directories)</u>**

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.

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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.

# NERC PROJECT UPDATES

**Latrice Harkness**

Director of Standards Development, NERC

**Jamie Calderon**

Manager of Standards Development, NERC

**Alison Oswald**

Manager of Standards Development, NERC

FORWARD TOGETHER RELIABILITYFIRST

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# NERC Standards Update

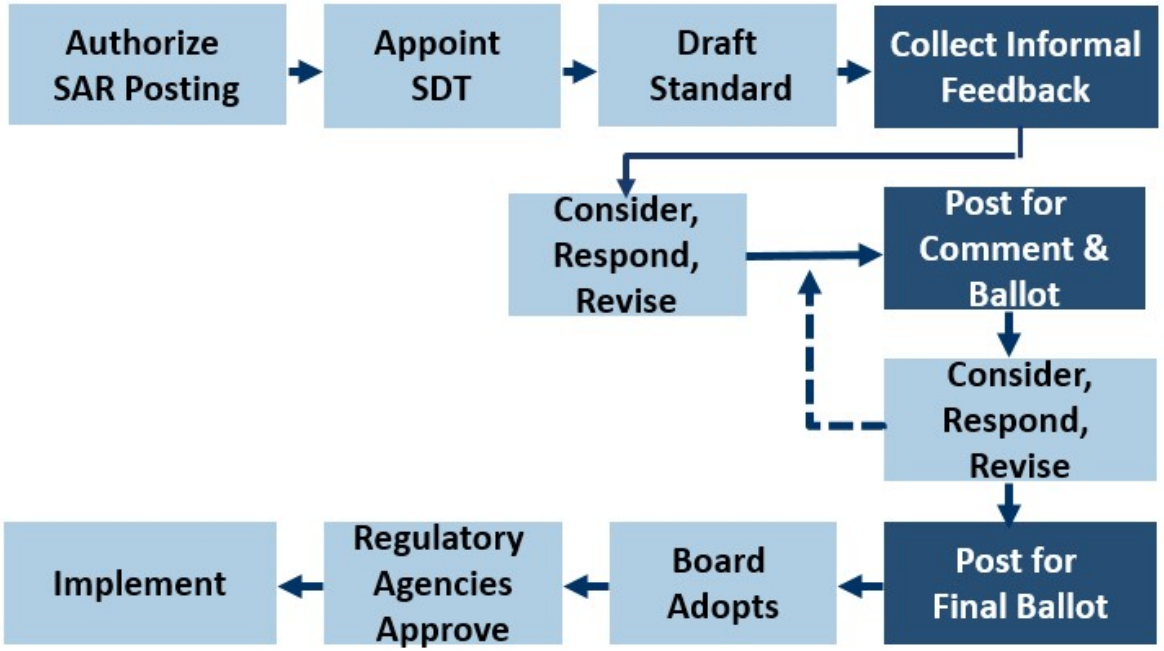
Latrice Harkness, Director of Standards Development, NERC
Jamie Calderon, Manager of Standards Development
Alison Oswald, Manager of Standards Development
RF Fall 2023 Workshop
September 27, 2023

RELIABILITY | RESILIENCE | SECURITY

# Overview

- Standard Development Process Review
- Standards Development Projects
- Project Updates
- Moving Forward
- Questions and Answers

# Standards Development Process



# Standards Development Projects

| Grid Transformation | Security Risks | Extreme Event | Critical Infrastructure Interdependencies |
|---|---|---|---|
| • 2020-02 Modifications to PRC-024 (Generator Ride-through)<br>• 2020-06 Verifications of Models and Data for Generators<br>• 2021-01 Modifications to MOD-025 and PRC-019<br>• 2021-02 Modifications to VAR-002<br>• 2021-04b Modifications to PRC-002-2<br>• 2022-02 MOD-032, TPL-001<br>• 2022-04 EMT Models in NERC MOD, TPL, FAC Standards<br>• 2023-01 EOP-004 IBR Event Reporting<br>• 2023-02 Performance of IBRs<br>• 2023-05 Modification to FAC-001/002 | 2016-02b Modifications to CIP Standards<br>2020-04 Modifications to CIP-012-1<br>2021-03 CIP-002<br>2022-05 Modifications to CIP-008<br>2023-03 CIP INSM<br>2023-04 CIP-003 LICRT<br>2023-06 CIP-014 Risk Assessment Refinement | • 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | • 2022-03 ERATF (Planning and Operations) |

# High Priority

| Focus | FERC Directives | NERC Board Resolutions |
| --- | --- | --- |
| • 2020-02 Modifications to PRC-024 (Generator Ride-through)<br>• 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination<br>• 2022-03 Energy Assurance with Energy-Constrained Resources<br>• 2023-06 CIP-014 Risk Assessment Refinement | • 2016-02 Modifications to CIP Standards<br>• 2023-03 Internal Network Security Monitoring (INSM)<br>• 2020-04 Modifications to CIP-012<br>• 2023-07 Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather | • 2023-04 Modifications to CIP-003<br>• Future GO-IBR Standards |

# Medium Priority

2023-02 Performance of IBRs

2023-01 EOP-004 IBR Event Reporting

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

2022-05 Modifications to CIP-008 Reporting Threshold

# Low Priority

## Projects

- 2017-01 Modifications to BAL-003 Phase II
- 2019-04 Modifications to PRC-005-6
- 2020-06 Verifications of Models and Data for Generators
- 2021-02 Modifications to VAR-002-4.1
- 2021-04 Modifications to PRC-002-2
- 2021-08 Modifications to FAC-008
- 2022-01 Reporting ACE Definition and Associated Terms
- 2022-02 Modifications to TPL-001-5.1 and MOD-032-1
- 2022-04 EMT Modeling

# Standards Overlap (O & P)

## MOD-032

- 2022-02 Modifications to TPL-001-5.1 and MOD-032-1
- 2022-04 EMT Modeling

## TPL-001

- 2022-02 Modifications to TPL-001-5.1 and MOD-032-1
- 2022-03 Energy Assurance with Energy-Constrained Resources
- 2022-04 EMT Modeling
- 2023-07 TPL-001 SAR on Extreme Weather
- Upcoming SAR on energy scenarios for Gas-Electric Interdepencies and DER

# Recommendations

- Submit waivers to expedite process
- Potential synchronization with other efforts
  - EMT Models with Compliance Filings and EMT training
  - Virtualization with the upcoming Cloud SARs
  - TPL-001 SDTs  will consider merging drafting efforts and allow directive on extreme weather to move forward first.

# Recommendations continued

- Slow or put on hold
  - Project 2017-01 Modifications to BAL-003 Phase II
  - Project 2019-04 Modifications to PRC-005-6
  - Project 2021-03 CIP-002 - remaining CIP-002 and CIP-014 SARs
  - Project 2016-02 Modifications to CIP Standards (Virtualization) - already under a waiver, but for the next ballot, if it fails, should be sent to the Security Working Group with the three cloud SARs that are being submitted
  - Project 2023-08 (pending posting) MOD-031 SAR
  - Projects that require definition considerations of DER

# Projects of Note

- Project 2021-01 Modifications to MOD-025 and PRC-019
  - The SARs propose revisions to MOD-025-2 and PRC-019-2 to address issues regarding verification and data reporting of generator active and reactive power capability.
- Project 2023-06 CIP-014 Risk Assessment Refinement
  - This SAR proposes modified requirements to the risk assessment conducted for applicable Transmission facilities in CIP-014-3.
  - SAR Comment and Solicitations for Nominations are now closed. Recommendations for drafting teams will be brought to the October SC.

# Projects of Note

- Project 2020-06 Verification of Models and Data for Generators
  - The SAR proposes revisions to MOD-026-1 and MOD-027-1 to clarify requirements related to IBRs and to require sufficient model verification to ensure accurate generator representation in dynamic simulations.
  - Project to prioritize creating definitions for IBR that will be utilized by other IBR-related Projects
  - Remainder of project to slow to assure resources are available to higher priority projects

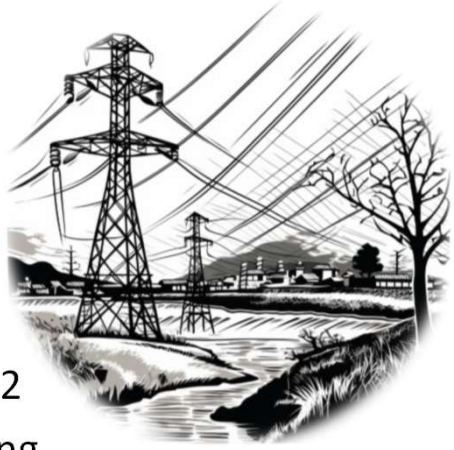
# Projects of Note

- Project 2020-02 Ride-Through
  - The SAR proposes new requirements to establish and coordinate performance criteria for IBR generators to assure adequate ride-through capability for new units.
    - Related to existing PRC-024. The team is pursuing an IBR version of PRC-024 currently and is in development stages. First ballot is anticipated for Q3 2023.
- Project 2023-02 Performance of IBRs
  - The SAR proposes new requirements regarding analysis responsibilities following the poor performance of generators during, or in response to, a BPS disturbance.
    - Related to existing PRC-004. The team is considering an IBR version of PRC-004 currently and is in early development stages.

⑩ ***Both projects will leverage the GO data recording capabilities being established within 2021-04b (Modifications to PRC-002-2)*

# Projects of Note

- Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination
  - Reliability Standards
    - EOP-011-3 (Emergency Preparedness and Operations)
    - EOP-012-1 (Extreme Cold Weather Preparedness and Operations)
  - Adopted by NERC Board of Trustees in October 2022
  - FERC issued an order on February 16, 2023 approving EOP-011-3 and EOP-012-1 while directing further revisions to clarify and enhance EOP-012-1.
  - The team has completed addressing the recommendations in phase 2 and is working to address the FERC directives in EOP-012.



# Projects of Note

- Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1
  - The SARs propose revisions to FAC-001, TPL-001, and MOD-032 to provide and verify EMT models during the interconnection process
  - Phase 1 is revising MOD-032
  - Additional Posting scheduled for early October
- Project 2022-03 Energy Assurance with Energy-Constrained Resources
  - The SAR proposes new requirements for operations and planning to assure energy availability/assurance is routinely evaluated.

# Projects of Note

- Project 2023-03 Internal Network Security Monitoring (INSM)
  - The SAR proposes new requirements to assure internal networks of high impact BCS and medium impact BCS with External Routable Connectivity are monitored and able to detect intrusions.
  - Initial draft anticipated for formal ballot in October 2023.

- Project 2021-03 CIP-002
  - This project is addressing four SARs
  - Field Test for Criterion 2.12
  - Initial posting scheduled for late September

# Questions and Answers

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# CIP Definitions

## Project 2016-02 Modifications to CIP Standards
## Draft 5

The standard drafting team (SDT) is seeking comment on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. The SDT is proposing acronyms to some currently approved and new glossary terms as shown in redline. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*CIP SDT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view.

**Table 1: Modified or Newly Proposed Definitions**

| NERC Glossary Term | Currently Approved Definition | CIP SDT Proposed New or Revised REDLINE TO Currently Approved |
|---|---|---|
| **BES Cyber Asset (BCA)** | A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. | A Cyber Asset or Virtual Cyber Asset that, if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the ~~reliable operation~~Reliable Operation of the Bulk Electric System~~.~~ (BES). Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. |
| **BES Cyber System (BCS)** | One or more BES Cyber Assets logically grouped | |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| **Update is Acronym only.** | by a responsible entity to perform one or more reliability tasks for a functional entity. | |
| **BES Cyber System Information (BCSI)** | Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System | Information about the BES Cyber System (BCS) that could be used to gain unauthorized access or pose a security threat to the ~~BES Cyber System~~BCS. BES Cyber System Information (BCSI) does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to ~~BES Cyber Systems~~BCS, such as, but not limited to, device names, individual IP addresses without context, ~~ESP~~Electronic Security Perimeter names, or policy statements. Examples of ~~BES Cyber System Information~~BCSI may include, but are not limited to, security procedures or security information about ~~BES~~BCS, Shared Cyber ~~Systems~~Infrastructure, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the ~~BES Cyber System~~BCS. |
| **CIP Senior Manager** | A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC | A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the NERC |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | CIP Standards, CIP-002 through CIP-011. | ~~CIP~~Critical Infrastructure Protection Cyber Security Standards~~, CIP-002 through CIP-011.~~. |
| **Cyber Assets** | Programmable electronic devices, including the hardware, software, and data in those devices. | Programmable electronic devices, excluding Shared Cyber Infrastructure, including the hardware, software, and data in those devices. Application containers are considered software of Virtual Cyber Assets (VCAs) or Cyber Assets. VCAs are not considered software or data of Cyber Assets. |
| **Cyber Security Incident** | A malicious act or suspicious event that:<br>- For a high or medium impact BES Cyber System, compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, or (3) an Electronic Access Control or Monitoring System; or<br>- Disrupts or attempts to disrupt the operation of a BES Cyber System | A malicious act or suspicious event that:<br>• ~~-~~For a high or medium impact BES Cyber System~~,~~ (BCS), compromises or attempts to compromise (1) an Electronic Security Perimeter, (2) a Physical Security Perimeter, ~~or~~ (3) an Electronic Access Control or Monitoring System; or (4) Shared Cyber Infrastructure; or<br>• ~~-~~Disrupts or attempts to disrupt the operation of a ~~BES Cyber System~~BCS. |
| **Cyber System**<br>***New Definition*** | | One or more Cyber Assets, Virtual Cyber Assets, or Shared Cyber Infrastructure. |
| **Electronic Access Control or Monitoring Systems (EACMS)** | Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber | Cyber ~~Assets~~System(s) that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | Systems. This includes Intermediate Systems. | Systems (BCS)~~. This includes Intermediate Systems.~~, including those not protected by an Electronic Security Perimeter used by the responsible entity to convert routable protocol communications to non-routable communications to a BCS. |
| **Electronic Access Point (EAP)** | A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter. | ~~A~~An electronic policy enforcement point or a Cyber Asset interface on an Electronic ~~Security Perimeter~~Access Control or Monitoring Systems that ~~allows~~controls routable communication ~~between~~to and from one or more BES Cyber Systems or their associated Protected Cyber Assets~~ outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.~~. |
| **External Routable Connectivity (ERC)** | The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection. | The ability to access a BES Cyber System ~~from a Cyber Asset that is outside of its associated~~through its Electronic Security Perimeter via a bi-directional routable protocol connection. |
| **Electronic Security Perimeter (ESP)** | The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol. | The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol; or a logical boundary defined by one or more Electronic Access Points. |
| **Interactive Remote Access (IRA)** | User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within | User-initiated electronic access by a person ~~employing a remote access client or other remote access technology~~ using a bi-directional routable protocol~~. Remote access originates from a Cyber Asset that is not an Intermediate~~ : |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications. | • To a Cyber System ~~and not located within any of the Responsible Entity's~~ protected by an Electronic Security Perimeter(s) ~~or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) (ESP);~~<br>• That is converted by the responsible entity to a non-routable protocol that allows access to a Cyber ~~Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants.~~ System; or<br>• To a Management Interface.<br><br>Interactive ~~r~~Remote ~~a~~Access does not include ~~system~~:<br>• Communication that originates from a Cyber System protected by any of the Responsible Entity's ESPs; or<br>System-to-system process communication~~s~~. |
| **Intermediate System** | A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter. | ~~A Cyber Asset~~One or ~~collection of Cyber Assets performing access control~~more Electronic Access Control or Monitoring Systems that are used to restrict Interactive Remote Access to only authorized users. ~~The Intermediate System must not be located inside the Electronic Security Perimeter.~~ |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| **Management Interface**<br>***New Definition*** | | An administrative interface that:<br>• Controls the processes of initializing, deploying, and configuring Shared Cyber Infrastructure;<br>• Is an autonomous subsystem that provides access to the console independently of the host system's CPU, firmware, and operating system; or<br>• Configures an Electronic Access Point. |
| **Physical Access Control Systems (PACS)** | Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers | Cyber ~~Assets~~Systems that control, alert, or log access to the Physical Security Perimeter(s) (PSP), exclusive of locally mounted hardware or devices at the ~~Physical Security Perimeter~~PSP such as motion sensors, electronic lock control mechanisms, and badge readers. |
| **Physical Security Perimeter (PSP)** | The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled. | The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, Shared Cyber Infrastructure, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled. |
| **Protected Cyber Asset (PCA)** | One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. | One or more Cyber Assets ~~connected using a routable protocol within~~ or ~~on~~Virtual Cyber Assets that:<br>• Are protected by an Electronic Security Perimeter ~~that is~~(ESP) but are not part of the highest impact BES Cyber System ~~within~~(BCS) protected by the same ~~Electronic Security Perimeter. The impact~~ |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | | ~~rating~~ESP; or<br>• Share CPU resources or memory resources with any part of ~~Protected Cyber Assets is equal to~~ the ~~highest rated BES~~BCS, excluding Virtual Cyber ~~System~~Assets that are being actively remediated in ~~the same ESP.~~an environment that isolates routable connectivity from BCS;<br>Excluding Transient Cyber Assets. |
| **Removable Media** | Storage media that (i) are not Cyber Assets, (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, a network within an ESP, or a Protected Cyber Asset. Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory. | Storage media that (i) are not Cyber Assets~~,~~ or Shared Cyber Infrastructure (SCI), (ii) are capable of transferring executable code, (iii) can be used to store, copy, move, or access data, and (iv) are directly connected for 30 consecutive calendar days or less to a BES Cyber Asset, SCI, a network ~~within~~protected by an ~~ESP~~Electronic Security Perimeter, or a Protected Cyber Asset. ~~Examples include, but are not limited to, floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.~~ |
| **Reportable Cyber Security Incident** | A Cyber Security Incident that compromised or disrupted:<br>- A BES Cyber System that performs one or more reliability tasks of a functional entity;<br>- An Electronic Security Perimeter of a high or medium impact BES Cyber System; or | A Cyber Security Incident that compromised or disrupted:<br>• ~~–~~A BES Cyber System (BCS) that performs one or more reliability tasks of a functional entity;<br>• ~~–~~An Electronic Security Perimeter of a high |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | - An Electronic Access Control or Monitoring System of a high or medium impact BES Cyber System | or medium impact ~~BES Cyber System; or~~BCS;<br>• ~~-~~An Electronic Access Control or Monitoring Systems of a high or medium impact ~~BES~~BCS; or<br>• Shared Cyber ~~System~~Infrastructure supporting a BCS. |
| **Shared Cyber Infrastructure (SCI)**<br>***New Definition*** | | One or more programmable electronic devices, including the software that shares the devices' resources, that:<br>• Hosts one or more Virtual Cyber Assets (VCA) included in a BES Cyber Systems (BCS) or their associated Electronic Access Control or Monitoring Systems (EACMS) or Physical Access Control Systems (PACS); and hosts one or more VCAs that are not included in, or associated with, BCS of the same impact categorization; or<br>• Provides storage resources required for system functionality of one or more Cyber Assets or VCAs included in a BCS or their associated EACMS or PACS; and also for one or more Cyber Assets or VCAs that are not included in, or associated with, BCS of the same impact categorization.<br>SCI does not include the supported VCAs or Cyber Assets with which it shares its resources. |
| **Transient Cyber Asset (TCA)** | A Cyber Asset that is: | A Cyber Asset or Virtual Cyber Asset (VCA) that is: |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | 1. capable of transmitting or transferring executable code,<br>2. not included in a BES Cyber System,<br>3. not a Protected Cyber Asset (PCA) associated with high or medium impact BES Cyber Systems, and<br>4. directly connected (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) for 30 consecutive calendar days or less to a:<br>• BES Cyber Asset,<br>• network within an Electronic Security Perimeter (ESP) containing high or medium impact BES Cyber Systems, or<br>• PCA associated with high or medium impact BES Cyber Systems.<br><br>Examples of Transient Cyber Assets include, but are not limited to, Cyber Assets used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes. | 1. ~~c~~Capable of transmitting or transferring executable code,<br>2. ~~n~~Not included in a BES Cyber System (BCS),<br>3. ~~n~~Not a Protected Cyber Asset (PCA) associated with high or medium impact ~~BES Cyber Systems~~BCS, and<br>4. ~~directly c~~Connected for 30 consecutive calendar days or less:<br>• On a network protected by an Electronic Security Perimeter (ESP) containing high or medium impact BCS, or<br>• Directly (e.g., using Ethernet, serial, Universal Serial Bus, or wireless including near field or Bluetooth communication) ~~for 30 consecutive calendar days or less to a:~~to a:<br>• BES Cyber Asset,<br>▪ ~~network within an Electronic Security Perimeter (ESP) containing high~~ or ~~medium impact BES Cyber Systems, or~~<br>▪ Shared Cyber Infrastructure, or<br>▪ PCA associated with high or medium impact ~~BES Cyber Systems~~BCS. |

| Table 1: Modified or Newly Proposed Definitions | | |
|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **CIP SDT Proposed New or Revised REDLINE TO Currently Approved** |
| | | ~~Examples of~~ Virtual machines hosted on a physical Transient Cyber Asset~~s~~ (TCA) are treated as software on that physical TCA. Examples of TCAs include, but are not limited to, Cyber Assets or VCAs used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes. |
| **Virtual Cyber Asset (VCA)**<br>***New Definition*** | | A logical instance of an operating system or firmware, currently executing on a virtual machine hosted on a BES Cyber Asset; Electronic Access Control or Monitoring System; Physical Access Control System; Protected Cyber Asset; or Shared Cyber Infrastructure (SCI).<br>Virtual Cyber Assets (VCAs) do not include:<br>• Logical instances that are being actively remediated in an environment that isolates routable connectivity from BES Cyber Systems;<br>• Dormant file-based images that contain operating systems or firmware; and<br>• SCI or Cyber Assets that host VCAs.<br>Application containers are considered software of VCAs or Cyber Assets. |

# 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~~April 18, 2023 |
| 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-003-23**

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

4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1.** Balancing AuthorityResponsible 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

5. **Effective Date:** See Implementation Plan for BAL-003-32.

# 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 annualFrequency Response Compliance Measure (FRCM) (as calculated and reported in accordance with Attachment A) that is greater than or -equal to one 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 one ~~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 Reporting ~~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 Reporting 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 Reporting 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 Reporting ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

**R5.** Each Generator Operator shall operate each generating unit/generating facility ~~that is~~ connected to ~~the~~an ~~interconnected~~Interconnection ~~transmission system~~ with its Governor in speed or frequency ~~responsive~~ controls mode unless: *[Violation Risk Factor = Medium] [Time Horizon = Real-time Operations]*

- The generating unit/generating facility is not equipped with a Governor;
- System operating conditions are incompatible with the generating unit/generating facility operating the Governor in speed or frequency control mode as determined by the Balancing Authority; or
- The generating unit/generating facility is being operated in start-up, shut-down, experiences a component failure, or other temporary mode that requires the Governor speed or frequency control mode to be temporarily disabled.

**5.1** Other control modes, such as outer loop control, shall not override the Primary Frequency Response of the Governor.

**M5.** The Generator Operator shall have evidence to show that it operated each generating unit/generating facility connected to an Interconnection with its Governor in speed or frequency control mode as specified in Requirement R5, Part R5.1, unless it meets one of the bulleted exceptions. Examples of suitable evidence may include, but is not limited to, performance testing, records showing Primary Frequency Response of a unit to frequency disturbances, appropriate documentation and/or control system settings that show the Governor is enabled (droop, deadband, control mode enable/disable, etc., as applicable). Requirement R5 does not require a Generator to operate with headroom, as stated in FERC Order No. 842, P109.

# C. Compliance

## 1. Compliance Monitoring Process

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

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

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

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Generator Operator shall retain evidence of notifications made to the Balancing Authority for the current year and the previous five (5) calendar years for Requirement R5 and Measure M5.
- 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.

## 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 Reporting 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 Reporting 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 Reporting 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 Reporting 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 Reporting ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the | The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its Reporting ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% | The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its Reporting ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% | The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its Reporting ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value.<br>OR |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | validated or calculated value. | of the validated or calculated value. | of the validated or calculated value. | The Balancing Authority failed to change the Frequency Bias Setting value used in its Reporting ACE calculation when providing Overlap Regulation Services. |
| **R5.** | N/A | N/A | N/A | The Generator Operator did not operate with the Governor in service and did not meet any of the exemption criteria.<br>OR<br>Generator is operating in a control mode that overrides the Governor response. |

## 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. | |

# Standard Attachments

**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 2023 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~~931** | | MW |
| Current IFRO (OY ~~2018~~2023) | **-~~1,09~~15** | **-~~858~~1096** | **-~~381~~412** | **-~~179~~211** | MW/0.1 Hz |
| ~~First Step target IFRO[1]Estimated Final target IFRO~~ | **~~-915~~890** | **~~-10181~~1096** | **~~-380~~** | **~~-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 ~~2017~~2023)**

IFRO = -(RLPC – CLR)/~~Max Delta Freq~~MDF/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.*** *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 Program (UVLS Program), 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*

An annual reduction in absolute value ~~To reduce risk, the Eastern~~of an Interconnection's IFRO due to change to the RLPC, CLR, and/or the MDF will be limited to no greater ~~stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step-down process, Interconnection Frequency Response Measure (FRM) declines by more~~ than 10 percent~~, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation~~ of the existing Interconnection's IFRO or -100MW/.10 Hz, 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 FRM as calculated by the ERO declines by more than 10 percent, the ERO will delay subsequent reduction in IFRO until such time that a determination can be made as to the cause of the 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 $\mathrm{Gen_{BA}}$ is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual $\mathrm{Load_{BA}}$ is total annual Load within the BAA.
- Annual $\mathrm{Gen_{Int}}$ is the sum of all Annual $\mathrm{Gen_{BA}}$ values reported in that I~~i~~nterconnection.
- Annual $\mathrm{Load_{Int}}$ is the sum of all Annual $\mathrm{Load_{BA}}$ 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.

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 ($F_A$)
- Actual Net Interchange ($NA_I$) – 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 ($NA_t$) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]~~

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

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

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

~~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*~~**** <br><br> **~~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.

# 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 | June 26, 2019 |
| SAR posted for comment | July 30, 2019-August 28, 2019 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal comment period with ballot | May 25, 2023 – July 10, 2023 |
| 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 PRC-005-7 Standard Drafting Team (SDT) proposes to modify the NERC Glossary of Terms definition of **Protection System** ~~to be modified~~:

**Protection System** – One or more of the following components:

- Protective relays and components of control systems which respond to ~~secondary~~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); and/or
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

This term is also used in other standards, as indicated below. The PRC-005-7 SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The PRC-005-7 SDT has determined that the proposed modified definition does not change the reliability intent of other requirements or definitions.

The Protection System definition was changed to ensure uniformity among all reliability standards. Components of control systems which respond to measured electrical quantities and provide protective functions provide the same functionality, and thereby present the same risk, to the Bulk Electric System as protective relays. The risk of such components has already been realized and addressed in certain standards (PRC-019 and PRC-24, for instance), but it is crucial that these devices be uniformly accepted for their functionality and risk to the Bulk Electric System in terms of configuration, physical and cyber security, operation, and redundancy.

Additionally, it is important to maintain reliability standards that are technology neutral and centered around risk to the Bulk Electric System. The previous definition of Protection System provided requirements for a specific technology (protective relays) and left ambiguity regarding these other devices which perform the same function. Likewise, to only address synchronous

generator excitation systems is again focusing on a specific technology and not the risk to the Bulk Electric System. It is for these reasons that these devices should be treated as components of a Protection System among all reliability standards to ensure not only that they are maintained, but that they are designed, configured, protected, and studied in a manner consistent with protective relays which provide the same functionality.

The proposed revisions to **Protection System** are intended 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.

- CIP-002-5.1a – BES Cyber System Categorization
- CIP-003-8 – Cyber Security – Security Management Controls
- CIP-005-6 – Cyber Security – Electronic Security Perimeter(s)
- CIP-005-7 – Cyber Security – Electronic Security Perimeter(s)
- CIP-006-6 – Cyber Security – Physical Security of BES Cyber Systems
- CIP-007-6 – Cyber Security – Systems Security Management
- CIP-008-6 – Cyber Security – Incident Reporting and Response Planning
- CIP-009-6 – Cyber Security – Recovery Plans for BES Cyber Systems
- CIP-010-3 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-010-4 – Cyber Security – Configuration Change Management and Vulnerability Assessments
- CIP-011-2 – Cyber Security – Information Protection
- CIP-013-2 – Cyber Security – Supply Chain Risk Management
- EOP-010-1 – Geomagnetic Disturbance Operations (in background section)
- IRO-010-2 – Reliability Coordinator Data Specification and Collection
- IRO-010-3 – Reliability Coordinator Data Specification and Collection
- PER-005-2 – Operations Personnel Training
- PER-006-1 – Specific Training for Personnel
- PRC-004-6 – Protection System Misoperation Identification and Correction
- PRC-012-2 – Remedial Action Schemes
- PRC-017-1 – Remedial Action Scheme Maintenance and Testing
- PRC-019-2 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
- PRC-023-4 – Transmission Relay Loadability
- PRC-024-3 – Frequency and Voltage Protection Settings for Generating Resources
- PRC-025-2 – Generator Relay Loadability
- PRC-026-1 – Relay Performance During Stable Power Swings
- PRC-027-1 – Coordination of Protection Systems for Performance During Faults
- TOP-003-4 – Operational Reliability Data
- TPL-001-4 – Transmission System Planning Performance Requirements

- TPL-001-5.1 – Transmission System Planning Performance Requirements
- TPL-007-4 – Transmission System Planned Performance for Geomagnetic Disturbance Events

# A. Introduction

1. **Title:** **Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance**

2. **Number: PRC-005-~~6~~7**

3. **Purpose:** To document and implement programs for the maintenance of all Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying affecting the reliability of the Bulk Electric System (BES) so that they are kept in working order.

4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1** Transmission Owner

   **4.1.2** Generator Owner

   **4.1.3** Distribution Provider

   **4.1.4** UFLS-Only Distribution Provider

   **4.2. Facilities:**

   **4.2.1** Protection Systems and Sudden Pressure Relaying that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)

   **4.2.2** Protection Systems used for underfrequency load-shedding systems installed per ERO underfrequency load-shedding requirements.

   **4.2.3** Protection Systems used for undervoltage load-shedding systems installed to prevent system voltage collapse or voltage instability for BES reliability.

   **4.2.4** Protection Systems installed as a Remedial Action Scheme (RAS) for BES reliability.

   **4.2.5** Protection Systems and Sudden Pressure Relaying for generator Facilities that are part of the BES, except for generators identified through Inclusion I4 of the BES definition, including:

   **4.2.5.1** Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.

   **4.2.5.2** Protection Systems and Sudden Pressure Relaying for generator step-up transformers for generators that are part of the BES.

   **4.2.5.3** Protection Systems and Sudden Pressure Relaying for station service or excitation transformers connected to the generator

bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays.

**4.2.6** Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:

**4.2.6.1** Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above.

**4.2.7** Automatic Reclosing[1], including:

**4.2.7.1** Automatic Reclosing applied on the terminals of Elements connected to the BES bus located at generating plant substations where the total installed gross generating plant capacity is greater than the gross capacity of the largest BES generating unit within the Balancing Authority Area or, if a member of a Reserve Sharing Group, the largest generating unit within the Reserve Sharing Group.[2]

**4.2.7.2** Automatic Reclosing applied on the terminals of all BES Elements at substations one bus away from generating plants specified in Section 4.2.7.1 when the substation is less than 10 circuit-miles from the generating plant substation.

**4.2.7.3** Automatic Reclosing applied as an integral part of an RAS specified in Section 4.2.4.

5. **Effective Date:** See the Implementation Plan for ~~this standard~~ PRC-005-7.

6. **Definitions Used in this Standard:**

**Automatic Reclosing** – Includes the following Components:

- Reclosing relay

[1] Automatic Reclosing addressed in Section 4.2.7.1 and 4.2.7.2 may be excluded if the equipment owner can demonstrate that a close-in three-phase fault present for twice the normal clearing time (capturing a minimum trip-close-trip time delay) does not result in a total loss of gross generation in the Interconnection exceeding the gross capacity of the largest relevant BES generating unit where the Automatic Reclosing is applied.

[2] The largest BES generating unit within the Balancing Authority Area or the largest generating unit within the Reserve Sharing Group, as applicable, is subject to change. As a result of such a change, the Automatic Reclosing Components subject to the standard could change effective on the date of such change.

- Supervisory relay(s) or function(s) – relay(s) or function(s) that perform voltage and/or sync check functions that enable or disable operation of the reclosing relay
- Voltage sensing devices associated with the supervisory relay(s) or function(s)
- Control circuitry associated with the reclosing relay or supervisory relay(s) or function(s)

**Sudden Pressure Relaying** – A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid-filled, wire-wound equipment
- Control circuitry associated with a fault pressure relay

**Unresolved Maintenance Issue** – A deficiency identified during a maintenance activity that causes the Component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action.

**Segment** – Components of a consistent design standard, or a particular model or type from a single manufacturer that typically share other common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual Components.

**Component Type** –

- Any one of the five specific elements of a Protection System
- Any one of the four specific elements of Automatic Reclosing
- Any one of the two specific elements of Sudden Pressure Relaying

**Component** – Any individual discrete piece of equipment included in a Protection System, Automatic Reclosing, or Sudden Pressure Relaying.

**Countable Event** – A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5, which requires corrective action or a Protection System Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component, Automatic Reclosing, or Sudden Pressure Relaying configuration or application errors are not included in Countable Events.

## B. Requirements and Measures

**R1.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems, Automatic Reclosing, and Sudden Pressure Relaying identified in Section 4.2, Facilities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning*]

The PSMP shall:

**1.1** Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type. All batteries, non-battery based energy storage and alternative electro-chemical based energy storage associated with the station dc supply Component Type of a Protection System shall be included in a time-based program as described in Table 1-4 and Table 3.

**1.2** Include the applicable monitored Component attributes applied to each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components.

**M1.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall have a documented PSMP in accordance with Requirement R1.

For each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time-based, performance-based, or a combination of these maintenance methods), and shall include all batteries, non-battery based energy storage and alternative electro-chemical based energy storage, associated with the station dc supply Component Types in a time-based program as described in Table 1-4 and Table 3. (Part 1.1)

For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for each Protection System, Automatic Reclosing, and Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. (Part 1.2)

**R2.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A to establish and

maintain its performance-based intervals. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M2.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that uses performance-based maintenance intervals shall have evidence that its current performance-based maintenance program(s) is in accordance with Requirement R2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

**R3.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Table 4-1 through 4-3, and Table 5. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**M3.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes time-based maintenance program(s) shall have evidence that it has maintained its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement R3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

**R4.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components that are included within the performance-based program(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

**M4.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider that utilizes performance-based maintenance intervals in accordance with Requirement R2 shall have evidence that it has implemented the PSMP for the Protection System, Automatic Reclosing, and Sudden Pressure Relaying Components included in its performance-based program in accordance with Requirement R4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

**R5.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M5.** Each Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

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

- For Requirement R1, the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep its current dated PSMP, as well as any superseded versions since the preceding compliance audit, including the documentation that specifies the type of maintenance program applied for each Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component Type.

- For Requirement R2, Requirement R3, and Requirement R4, in cases where the interval of the maintenance activity is longer than the audit cycle, the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep documentation of the most recent performance of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component. In cases where the interval of the maintenance activity is shorter than the audit cycle, documentation of all performances (in accordance with the tables) of that maintenance activity for the Protection System, Automatic Reclosing, or Sudden Pressure Relaying Component since the previous scheduled audit date shall be retained.

- For Requirement R5 the Transmission Owner, Generator Owner, ~~and~~ Distribution Provider, and UFLS-only Distribution Provider shall each keep documentation of Unresolved Maintenance Issues identified by the entity since the last audit, including all that were resolved since the last audit.

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

~~**1.3.**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

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

~~None~~

## Table of Compliance Elements

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| R1 | The entity's PSMP failed to specify whether one Component Type is being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). | The entity's PSMP failed to specify whether two Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1). | The entity's PSMP failed to specify whether three Component Types are being addressed by time-based or performance-based maintenance, or a combination of both. (Part 1.1).<br>OR<br>The entity's PSMP failed to include the applicable monitoring attributes applied to each Component Type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5 where monitoring is used to extend the maintenance intervals beyond those specified for unmonitored Components (Part 1.2). | The entity failed to establish a PSMP.<br>OR<br>The entity's PSMP failed to specify whether four or more Component Types are being addressed by time-based or performance-based maintenance, or a combination of both (Part 1.1).<br>OR<br>The entity's PSMP failed to include applicable station batteries, non-battery based energy storage and alternative electro-chemical based energy storage, associated with the dc supply Component Types in a time-based program (Part 1.1). |
| R2 | The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within three years. | NA | The entity uses performance-based maintenance intervals in its PSMP but failed to reduce Countable Events to no more than 4% within four years. | The entity uses performance-based maintenance intervals in its PSMP but:<br>1) Failed to establish the technical justification described within Requirement R2 for the initial use of the performance-based PSMP<br>OR<br>2) Failed to reduce Countable Events to no more than 4% within five years |

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | OR<br>3) Maintained a Segment with less than 60 Components<br>OR<br>4) Failed to:<br>• Annually update the list of Components,<br>OR<br>• Annually perform maintenance on the greater of 5% of the Segment population or 3 Components,<br>OR<br>• Annually analyze the program activities and results for each Segment. |
| R3 | For Components included within a time-based maintenance program, the entity failed to maintain 5% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5. | For Components included within a time-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5. | For Components included within a time-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5. | For Components included within a time-based maintenance program, the entity failed to maintain more than 15% of the total Components included within a specific Component Type in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, Table 3, Tables 4-1 through 4-3, and Table 5. |

| Requirement Number | Lower VSL | Moderate VSL | High VSL | Severe VSL |
|---|---|---|---|---|
| | | | | |
| R4 | For Components included within a performance-based maintenance program, the entity failed to maintain 5% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. | For Components included within a performance-based maintenance program, the entity failed to maintain more than 5% but 10% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. | For Components included within a performance-based maintenance program, the entity failed to maintain more than 10% but 15% or less of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. | For Components included within a performance-based maintenance program, the entity failed to maintain more than 15% of the annual scheduled maintenance for a specific Component Type in accordance with their performance-based PSMP. |
| R5 | The entity failed to undertake efforts to correct five (5) or fewer identified Unresolved Maintenance Issues. | The entity failed to undertake efforts to correct greater than five (5) but less than or equal to 10 identified Unresolved Maintenance Issues. | The entity failed to undertake efforts to correct greater than 10 but less than or equal to 15 identified Unresolved Maintenance Issues. | The entity failed to undertake efforts to correct greater than 15 identified Unresolved Maintenance Issues. |

## D. Regional Variances

None.

## E. ~~Interpretations~~Associated Documents

~~None.~~The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. *Supplementary Reference and FAQ - PRC-005-7 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (March 2023)
2. Technical Rationale for Modification of Protection System Definition (March 2023)
3. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)

## ~~Supplemental Reference Documents~~

~~The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.~~

~~1. *Supplementary Reference and FAQ - PRC-005-6 Protection System Maintenance,* Protection System Maintenance and Testing Standard Drafting Team (July 2015)~~

~~2. *Considerations for Maintenance and Testing of Auto-reclosing Schemes*, NERC System Analysis and Modeling Subcommittee, and NERC System Protection and Control Subcommittee (November 2012)~~

~~3. *Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities – SPCS Input for Standard Development in Response to FERC Order No. 758,* NERC System Protection and Control Subcommittee (December 2013)~~

4. ~~*Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities* – Supplemental Information to Support Project 2007-17.3: Protection System Maintenance and Testing (October 31, 2014)~~

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 0 | February 8, 2005 | Adopted by NERC Board of Trustees | New |
| 1 | February 7, 2006 | Adopted by NERC Board of Trustees | 1. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)."<br>2. Added "periods" to items where appropriate.<br>Changed "Timeframe" to "Time Frame" in item D, 1.2. |
| 1 | March 16, 2007 | PRC-005-1 Approved by FERC. Docket No. RM06-16-000 | |
| 1a | February 17, 2011 | Adopted by NERC Board of Trustees | Added Appendix 1 - Interpretation regarding applicability of standard to protection of radially connected transformers developed in Project 2009-17 |
| 1a | September 26, 2011 | Approved by FERC. Docket No. RD11-5-000 | |
| 1b | November 5, 2009 | Adopted by NERC Board of Trustees | Interpretation of R1, R1.1, and R1.2 developed by Project 2009-10 |
| 1b | February 3, 2012 | FERC Order approving revised definition of "Protection System" | Per footnote 8 of FERC's order, the definition of "Protection System" supersedes interpretation "b" of PRC-005-1b upon the effective date of the modified definition (i.e., April 1, 2013)<br>*See N. Amer. Elec. Reliability Corp.*, 138 FERC ¶ 61,095 (February 3, 2012). |
| 1b | February 3, 2012 | PRC-005-1b Approved by FERC.<br>Docket No. RM10-5-000 | |

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1.1b | May 9, 2012 | Adopted by NERC Board of Trustees | Errata change developed by Project 2010-07, clarified inclusion of generator interconnection Facility in Generator Owner's responsibility |
| 1.1b | September 19, 2013 | PRC-005-1.1b Approved by FERC. Docket No. RM12-16-000 | |
| 2 | November 7, 2012 | Adopted by NERC Board of Trustees | Project 2007-17 - Complete revision, absorbing maintenance requirements from PRC-005-1.1b, PRC-008-0, PRC-011-0, PRC-017-0 |
| 2 | October 17, 2013 | Approved by NERC Standards Committee | Errata Change: The Standards Committee approved an errata change to the implementation plan for PRC-005-2 to add the phrase "or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities;" to the second sentence under the "Retirement of Existing Standards" section. (no change to standard version number) |
| 2 | December 19, 2013 | PRC-005-2 Approved by FERC. Docket No. RM13-7-000 | |
| 2 | March 7, 2014 | Adopted by NERC Board of Trustees | Modified R1 VSL in response to FERC directive (no change to standard version number) |
| 2(i) | November 13, 2014 | Adopted by NERC Board of Trustees | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources |
| 2(i) | May 29, 2015 | PRC-005-2(i) Approved by FERC. Docket No. RD15-3-000 | |

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 2(ii) | November 13, 2014 | Adopted by NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
| 3 | November 7, 2013 | Adopted by the NERC Board of Trustees | Revised to address the FERC directive in Order No. 758 to include Automatic Reclosing in maintenance programs |

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 3 | February 12, 2014 | Approved by NERC Standards Committee | Errata Change: The Standards Committee approved errata changes to correct capitalization of certain defined terms within the definitions of “Unresolved Maintenance Issue” and “Protection System Maintenance Program”. The changes will be reflected in the definitions section of PRC-005-3 for “Unresolved Maintenance Issue” and in the NERC Glossary of Terms for “Protection System Maintenance Program". (no change to standard version number) |
| 3 | March 7, 2014 | Adopted by NERC Board of Trustees | Modified R1 VSL in response to FERC directive (no change to standard version number) |
| 3 | January 22, 2015 | PRC-005-3 Approved by FERC. Docket No. RM14-8-000 | |
| 3(i) | November 13, 2014 | Adopted by NERC Board of Trustees | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources |
| 3(i) | May 29, 2015 | PRC-005-3(i) Approved by FERC. Docket No. RD15-3-000 | |
| 3(ii) | November 13, 2014 | Adopted by NERC Board of Trustees | Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS |
| 4 | November 13, 2014 | Adopted by NERC Board of Trustees | Added Sudden Pressure Relaying in response to FERC Order No. 758 |
| 4 | Sept 17, 2015 | PRC-005-4 Approved by FERC. Docket No. RM15-9-000 | |

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 5 | May 7, 2015 | Adopted by NERC Board of Trustees | Applicability section revised by Project 2014-01 to clarify application of Requirements to BES dispersed power producing resources. |
| 6 | November 5, 2015 | Adopted by NERC Board of Trustees | Revised to add supervisory relays, the voltage sensing devices, and the associated control circuitry to Automatic Reclosing in accordance with the directives in FERC Order 803. |
| 6 | December 18, 2015 | FERC Letter Order approving PRC-005-6. Docket No. RD16-2-000. | |
| 7 | TBD | Adopted by NERC Board of Trustees | |

| Table 1-1<br>Component Type - Protective Relays and Components of control systems which respond to measured electrical quantities and provide protective functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval**[3] | **Maintenance Activities** |
| Any unmonitored protective relay/Components not having all the monitoring attributes of a category below. | 6 Calendar Years | For all unmonitored relays/Components:<br>• Verify that protective function settings are as specified.<br>For non-microprocessor relays/Components:<br>• Test and, if necessary calibrate.<br>For microprocessor relays/Components:<br>• Verify operation of the relay/Components inputs and outputs that are essential to proper functioning of the Protection System.<br>• Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System. |

[3] For the tables in this standard, a calendar year starts on the first day of a new year (January 1) after a maintenance activity has been completed.
For the tables in this standard, a calendar month starts on the first day of the first month after a maintenance activity has been completed.

| Table 1-1<br>Component Type - Protective Relays and Components of control systems which respond to measured electrical quantities and provide protective functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval**[3] | **Maintenance Activities** |
| Monitored microprocessor protective relay/Components with the following:<br>• Internal self-diagnosis and alarming (see Table 2).<br>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.<br>• Alarming for power supply failure (see Table 2). | 12 Calendar Years | Verify:<br>• Protective function ~~S~~settings are as specified.<br>• Operation of the relay/Components inputs and outputs that are essential to proper functioning of the Protection System.<br>• Acceptable measurement of power system input values that are essential to proper functioning of the Protection System. |
| Monitored microprocessor protective relay/Components with preceding row attributes and the following:<br>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).<br>• Alarming for change of settings (See Table 2). | 12 Calendar Years | Verify only the unmonitored relay~~/~~/Component inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-2<br>Component Type - Communications Systems<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below. | 4 Calendar Months | Verify that the communications system is functional. |
| | 6 Calendar Years | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |
| Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function (See Table 2). | 12 Calendar Years | Verify that the communications system meets performance criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate).<br>Verify operation of communications system inputs and outputs that are essential to proper functioning of the Protection System. |

| | | |
|---|---|---|
| Any communications system with all of the following:<br>• Continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied (e.g. signal level, reflected power, or data error rate, and alarming for excessive performance degradation)~~.~~ (See Table 2)<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2). | 12 Calendar Years | Verify only the unmonitored communications system inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 1-3<br>Component Type - Voltage and Current Sensing Devices Providing Inputs necessary for the correct operation of~~to~~ Protective Relays<br>Excluding distributed UFLS and distributed UVLS (see Table 3) | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any voltage and current sensing devices not having monitoring attributes of the category below. | 12 Calendar Years | Verify that current and voltage signal values are provided to the protective relays or Components of control system. |
| Voltage and Current Sensing devices connected to microprocessor relays/control system Components with ac measurements that are continuously verified by comparison of sensing input values~~, as measured by the microprocessor relay,~~ to an independent ac measurement source, with alarming for unacceptable error or failure (see Table 2). | No periodic maintenance specified | None. |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System Station dc supply using Vented Lead-Acid (VLA) batteries not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage.<br>Inspect:<br>• Electrolyte level.<br>• For unintentional grounds. |

| Table 1-4(a)<br>Component Type – Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| | 18 Calendar Months | Verify:<br>• Float voltage of battery charger.<br>• Battery continuity.<br>• Battery terminal connection resistance.<br>• Battery intercell or unit-to-unit connection resistance.<br>Inspect:<br>• Cell condition of all individual battery cells where cells are visible – or measure battery cell/unit internal ohmic values where the cells are not visible.<br>• Physical condition of battery rack. |
| | 18 Calendar Months<br>-or-<br>6 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System Station dc supply with Valve Regulated Lead-Acid (VRLA) batteries not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage.<br>Inspect:<br>• For unintentional grounds. |
| | 6 Calendar Months | Inspect:<br>• Condition of all individual units by measuring battery cell/unit internal ohmic values. |

| Table 1-4(b)<br>Component Type – Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS systems, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| | 18 Calendar Months | Verify:<br>• Float voltage of battery charger.<br>• Battery continuity.<br>• Battery terminal connection resistance.<br>• Battery intercell or unit-to-unit connection resistance.<br>Inspect:<br>• Physical condition of battery rack. |
| | 6 Calendar Months<br>-or-<br>3 Calendar Years | Verify that the station battery can perform as manufactured by evaluating cell/unit measurements indicative of battery performance (e.g. internal ohmic values or float current) against the station battery baseline.<br>-or-<br>Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System Station dc supply **Nickel-Cadmium (NiCad) batteries** not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage.<br>Inspect:<br>• Electrolyte level.<br>• For unintentional grounds. |
| | 18 Calendar Months | Verify:<br>• Float voltage of battery charger.<br>• Battery continuity.<br>• Battery terminal connection resistance.<br>• Battery intercell or unit-to-unit connection resistance.<br>Inspect:<br>• Cell condition of all individual battery cells.<br>• Physical condition of battery rack. |

| Table 1-4(c)<br>Component Type – Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| | 6 Calendar Years | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-4(d)<br>Component Type – Protection System Station dc Supply Using Non Battery Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br><br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any Protection System station dc supply not using a battery and not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage.<br>Inspect:<br>• For unintentional grounds. |
| | 18 Calendar Months | Inspect:<br>Condition of non-battery based dc supply. |
| | 6 Calendar Years | Verify that the dc supply can perform as manufactured when ac power is not present. |

| Table 1-4(e)<br>Component Type – Protection System Station dc Supply for non-BES Interrupting Devices for RAS, non-distributed UFLS, and non-distributed UVLS systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any Protection System dc supply used for tripping only non-BES interrupting devices as part of a RAS, non-distributed UFLS, or non-distributed UVLS system and not having monitoring attributes of Table 1-4(f). | When control circuits are verified (See Table 1-5) | Verify Station dc supply voltage. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any station dc supply with high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure (See Table 2). | No periodic maintenance specified | No periodic verification of station dc supply voltage is required. |
| Any battery based station dc supply with electrolyte level monitoring and alarming in every cell (See Table 2). | | No periodic inspection of the electrolyte level for each cell is required. |
| Any station dc supply with unintentional dc ground monitoring and alarming (See Table 2). | | No periodic inspection of unintentional dc grounds is required. |
| Any station dc supply with charger float voltage monitoring and alarming to ensure correct float voltage is being applied on the station dc supply (See Table 2). | | No periodic verification of float voltage or output voltage monitoring of battery charger is required. |
| Any battery based station dc supply with monitoring and alarming of battery string continuity (See Table 2). | | No periodic verification of the battery continuity is required. |
| Any alternative electro-chemical based energy storage ~~battery based~~ station dc supply with monitoring and alarming of battery string(s) continuity ~~the intercell and/or terminal connection detail resistance of the entire battery~~ (See Table 2). | | No periodic verification of the intercell and terminal connection resistance is required. |
| Any battery based station dc supply with monitoring and alarming of the intercell and/or terminal connection detail resistance of the entire battery ~~Any Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA) station battery with internal ohmic value or float current monitoring and alarming, and~~ | | No periodic verification of the intercell and terminal connection resistance is required ~~evaluation relative to baseline of battery cell/unit measurements indicative of battery performance is required to verify the station battery can perform as manufactured~~. |

| Table 1-4(f)<br>Exclusions for Protection System Station dc Supply Monitoring Devices and Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| ~~evaluating present values relative to baseline internal ohmic values for every cell/unit~~ (See Table 2). | | |
| Any alternative electro-chemical based energy storage ~~Valve Regulated Lead-Acid (VRLA) or Vented Lead-Acid (VLA)~~ station dc supply ~~battery~~ with monitoring and alarming of integrity of all battery electrical connections~~each cell/unit internal ohmic value~~ (See Table 2). | | No periodic verification of the battery continuity ~~inspection of the condition of all individual units by measuring battery cell/unit internal ohmic values of a station VRLA or Vented Lead-Acid (VLA) battery~~ is required. |

| Table 1-4(g)<br>Component Type – Protection System Station dc Supply Using Alternative Electro-chemical Based Energy Storage<br>Excluding distributed UFLS and distributed UVLS (see Table 3)<br>Protection System Station dc supply used only for non-BES interrupting devices for RAS, non-distributed UFLS system, or non-distributed UVLS systems is excluded (see Table 1-4(e)). | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Protection System station dc supply with alternative electro-chemical based energy storage not having monitoring attributes of Table 1-4(f). | 4 Calendar Months | Verify:<br>• Station dc supply voltage.<br>Inspect:<br>• For unintentional grounds. |
| | 18 Calendar Months | Verify:<br>• Output voltage of battery charger.<br>• Battery continuity.<br>• Integrity of all battery electrical connections.<br>Inspect:<br>• Condition of alternative electro-chemical based energy storage station dc supply.<br>• Physical condition of battery rack/cabinet/enclosure. |
| | 1/3 of estimated lifetime (maximum of 6 years) | Verify that the station battery can perform as manufactured by conducting a performance or modified performance capacity test of the entire battery bank. |

| Table 1-5<br>Component Type - Control Circuitry Associated With Protective Functions<br>Excluding distributed UFLS and distributed UVLS (see Table 3), Automatic Reclosing (see Table 4), and Sudden Pressure Relaying (see Table 5)<br>Note: Table requirements apply to all Control Circuitry Components of Protection Systems, and RAS except as noted. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices (regardless of any monitoring of the control circuitry). | 6 Calendar Years | Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device. |
| Electromechanical lockout devices which are directly in a trip path from the protective relay or Component of control system to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 Calendar Years | Verify electrical operation of electromechanical lockout devices. |
| Unmonitored control circuitry associated with RAS.<br>(See Table 4-2(b) for RAS which include Automatic Reclosing.) | 12 Calendar Years | Verify all paths of the control circuits essential for proper operation of the RAS. |
| Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays. | 12 Calendar Years | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with protective functions and/or RAS whose integrity is monitored and alarmed (See Table 2). | No periodic maintenance specified | None. |

| Table 2 – Alarming Paths and Monitoring<br>In Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 alarm attributes used to justify extended maximum maintenance intervals and/or reduced maintenance activities are subject to the following maintenance requirements | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any alarm path through which alarms in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 are conveyed from the alarm origin to the location where corrective action can be initiated, and not having all the attributes of the "Alarm Path with monitoring" category below.<br><br>Alarms are reported within 24 hours of detection to a location where corrective action can be initiated. | 12 Calendar Years | Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. |
| Alarm Path with monitoring:<br><br>The location where corrective action is taken receives an alarm within 24 hours for failure of any portion of the alarming path from the alarm origin to the location where corrective action can be initiated. | No periodic maintenance specified | None. |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any unmonitored protective relay/Component not having all the monitoring attributes of a category below. | 6 Calendar Years | Verify that settings are as specified.<br>For non-microprocessor relays/Components:<br>• Test and, if necessary calibrate.<br>For microprocessor relays/Components:<br>• Verify operation of the ~~relay~~ inputs and outputs that are essential to proper functioning of the Protection System.<br>• Verify acceptable measurement of power system input values that are essential to proper functioning of the Protection System. |
| Monitored microprocessor protective relay/Component with the following:<br>• Internal self-diagnosis and alarming (See Table 2).<br>• Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics.<br>Alarming for power supply failure (See Table 2). | 12 Calendar Years | Verify:<br>• Protective function ~~S~~settings are as specified.<br>• Operation of the relay inputs and outputs that are essential to proper functioning of the Protection System.<br>• Acceptable measurement of power system input values that are essential to proper functioning of the Protection System. |
| Monitored microprocessor protective relay with preceding row attributes and the following: | 12 Calendar Years | Verify only the unmonitored ~~relay~~ inputs and outputs that are essential to proper functioning of the Protection System. |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| • AC measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2).<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).<br>Alarming for change of settings (See Table 2). | | |
| Voltage and/or current sensing devices associated with UFLS or UVLS systems. | 12 Calendar Years | Verify that current and/or voltage signal values are provided to the protective relays/Components. |
| Protection System dc supply for tripping non-BES interrupting devices used only for a UFLS or UVLS system. | 12 Calendar Years | Verify Protection System dc supply voltage. |
| Control circuitry between the UFLS or UVLS ~~relays~~ device and electromechanical lockout and/or tripping auxiliary devices (excludes non-BES interrupting device trip coils). | 12 Calendar Years | Verify the path from the ~~relay~~ device to the lockout and/or tripping auxiliary relay (including essential supervisory logic). |
| Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems (excludes non-BES interrupting device trip coils). | 12 Calendar Years | Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices. |
| Control circuitry between the electromechanical lockout and/or tripping auxiliary devices and the non-BES interrupting devices in UFLS or UVLS systems, or between UFLS or UVLS ~~relays~~ devices (with no interposing electromechanical lockout or auxiliary device) and the non-BES interrupting devices (excludes non-BES interrupting device trip coils). | No periodic maintenance specified | None. |

| Table 3<br>Maintenance Activities and Intervals for distributed UFLS and distributed UVLS Systems | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Trip coils of non-BES interrupting devices in UFLS or UVLS systems. | No periodic maintenance specified | None. |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing and Supervisory Relay<br>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any unmonitored reclosing relay or supervisory relay not having all the monitoring attributes of a category below. | 6 Calendar Years | Verify that settings are as specified.<br>For non-microprocessor reclosing or supervisory relays:<br>• Test and, if necessary calibrate<br>For microprocessor reclosing or supervisory relays:<br>• Verify operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.<br>For microprocessor supervisory relays:<br>• Verify acceptable measurement of power system input values. |
| • Monitored microprocessor reclosing relay or supervisory relay with the following: Internal self-diagnosis and alarming (See Table 2).<br>• Alarming for power supply failure (See Table 2).<br>For supervisory relay:<br>• Voltage waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics. | 12 Calendar Years | Verify:<br>• Settings are as specified.<br>• Operation of the relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing.<br>For supervisory relays:<br>• Verify acceptable measurement of power system input values. |

| Table 4-1<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Reclosing and Supervisory Relay<br>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-1 through 1-5, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Monitored microprocessor reclosing relay or supervisory relay with preceding row attributes and the following:<br>• Some or all binary or status inputs and control outputs are monitored by a process that continuously demonstrates ability to perform as designed, with alarming for failure (See Table 2).<br>• Alarming for change of settings (See Table 2).<br>For supervisory relay:<br>• Ac measurements are continuously verified by comparison to an independent ac measurement source, with alarming for excessive error (See Table 2). | 12 Calendar Years | Verify only the unmonitored relay inputs and outputs that are essential to proper functioning of the Automatic Reclosing. |

| Table 4-2(a)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that are NOT an Integral Part of an RAS<br>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Unmonitored Control circuitry associated with Automatic Reclosing that is not an integral part of an RAS. | 12 Calendar Years | Verify that Automatic Reclosing, upon initiation, does not issue a premature closing command to the close circuitry. |
| Control circuitry associated with Automatic Reclosing that is not part of an RAS and is monitored and alarmed for conditions that would result in a premature closing command. (See Table 2) | No periodic maintenance specified | None. |

| Table 4-2(b)<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Control Circuitry Associated with Reclosing and Supervisory Relays that ARE an Integral Part of an RAS<br>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Close coils or actuators of circuit breakers or similar devices that are used in conjunction with Automatic Reclosing as part of an RAS (regardless of any monitoring of the control circuitry). | 6 Calendar Years | Verify that each close coil or actuator is able to operate the circuit breaker or mitigating device. |
| Unmonitored close control circuitry associated with Automatic Reclosing used as an integral part of an RAS. | 12 Calendar Years | Verify all paths of the control circuits associated with Automatic Reclosing that are essential for proper operation of the RAS. |
| Control circuitry associated with Automatic Reclosing that is an integral part of an RAS whose integrity is monitored and alarmed. (See Table 2) | No periodic maintenance specified | None. |

| Table 4-3<br>Maintenance Activities and Intervals for Automatic Reclosing Components<br>Component Type – Voltage Sensing Devices Associated with Supervisory Relays<br>Note: In cases where Components of Automatic Reclosing are common to Components listed in Table 1-3, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any voltage sensing devices not having monitoring attributes of the category below. | 12 Calendar Years | Verify that voltage signal values are provided to the supervisory relays. |
| Voltage sensing devices that are connected to microprocessor supervisory relays with ac measurements that are continuously verified by comparison of sensing input value, as measured by the microprocessor relay, to an independent ac measurement source, with alarming for unacceptable error or failure. (See Table 2) | No periodic maintenance specified | None. |

| Table 5<br>Maintenance Activities and Intervals for Sudden Pressure Relaying<br>Note: In cases where Components of Sudden Pressure Relaying are common to Components listed in Table 1-5, the Components only need to be tested once during a distinct maintenance interval. | | |
|---|---|---|
| **Component Attributes** | **Maximum Maintenance Interval** | **Maintenance Activities** |
| Any fault pressure relay. | 6 Calendar Years | Verify the pressure or flow sensing mechanism is operable. |
| Electromechanical lockout devices which are directly in a trip path from the fault pressure relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry). | 6 Calendar Years | Verify electrical operation of electromechanical lockout devices. |
| Unmonitored control circuitry associated with Sudden Pressure Relaying. | 12 Calendar Years | Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices. |
| Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed (See Table 2). | No periodic maintenance specified | None. |

# ~~Standard Attachments~~
# PRC-005 — Attachment A

**Criteria for a Performance-Based Protection System Maintenance Program**

**Purpose:** To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

**To establish the technical justification for the initial use of a performance-based PSMP:**

1. Develop a list with a description of Components included in each designated Segment, with a minimum Segment population of 60 Components.
2. Maintain the Components in each Segment according to the time-based maximum allowable intervals established in Tables 1-1 through 1-5, Table 3, Tables 4-1 through 4-3, and Table 5 until results of maintenance activities for the Segment are available for a minimum of 30 individual Components of the Segment.
3. Document the maintenance program activities and results for each Segment, including maintenance dates and Countable Events for each included Component.
4. Analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

**To maintain the technical justification for the ongoing use of a performance-based PSMP:**

1. At least annually, update the list of Components and Segments and/or description if any changes occur within the Segment.
2. Perform maintenance on the greater of 5% of the Components (addressed in the performance based PSMP) in each Segment or 3 individual Components within the Segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each Segment to determine the overall performance of the Segment.
4. Using the prior year's data, determine the maximum allowable maintenance interval for each Segment such that the Segment experiences Countable Events on no more than 4% of the Components within the Segment, for the greater of either the last 30 Components maintained or all Components maintained in the previous year.

If the Components in a Segment maintained through a performance-based PSMP experience 4% or more Countable Events, develop, document, and implement an action plan to reduce the Countable Events to less than 4% of the Segment population within 3 years.

## ~~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 revisions to Automatic Reclosing:~~**
~~To address directives from FERC Order No. 803 addressing Automatic Reclosing, the definition for Automatic Reclosing was revised to add supervisory relays, the associated voltage sensing devices, and the associated control circuitry.~~

**~~Rationale for revisions to Component Type:~~**
~~With the revision of the definition of Automatic Reclosing, there are four specific elements of this definition, rather than two as stated in the prior version.~~

# 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 | September 2023 |
| 10-day final ballot | December 2023 |
| Board adoption | December 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, integrity, and 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 in 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 risk(s) posed by unauthorized disclosure and unauthorized modification of data used in 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 the loss of the ability to communicate Real-time Assessment and Real-time monitoring ~~for transmitting Real-time Assessment and Real-time monitoring~~ data between Control Centers;

**1.3.** Identification of method(s) used to initiate the recovery of 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, 1.2, and 1.3; 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). Examples of methods identified in the plan(s) may include, but are not limited to, one or more of the following for each part:

Part 1.1

- Methods of mitigation used to protect against the unauthorized disclosure and unauthorized modification of the data (e.g., data masking, encryption/decryption) while such data is being transmitted between Control Centers
- Physical access restrictions to unencrypted portions of the network

Part 1.2

- Identification of alternative communication paths or methods 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, applicable sections of CIP-009 recovery plan(s), or similar technical recovery plans
- Documentation of the process to restore assets and systems that provide communications
- Process or procedure to contact a communications link vendor to initiate and or verify restoration of service

Part 1.4

- Descriptions or logical diagrams indicating where the implemented methods reside
- Identification of points within the infrastructure where the implemented methods reside
- Third party Agreements detailing where the methods are implemented if such methods are implemented by the 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;<br>Or<br>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 | Revised under Project 2020-04 |

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

## Background:

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. The terms proposed below are intended to be used in MOD-026-2 and other inverter-based resource related standards.

## Term(s):

**Power Electronic Device (PED):** Any device connected to the ac power system through a power electronic interface that generates or transmits active power or reactive power, or absorbs active power for the purposes of re-injecting it at a later time. This term excludes any load.

**Inverter-Based Resource (IBR):** Any source of electric power consisting of one or more Power Electronic Devices (PEDs), that operates as a single resource, supplies primarily active power, and connects to the Bulk Power System. An IBR plant/facility includes the Power Electronic Devices, and the equipment designed primarily for delivering the power to a common point of connection (e.g. step-up transformers, collector system(s), main power transformer(s), and power plant controller(s)).

**Technical Rationale and Considerations:**

- A Power Electronic Device is inclusive of multiple technologies that use a power electronic interface, and is not limited to generators. Power Electronic Device examples include type 3 wind generators, type 4 wind generators, solar photovoltaic inverters, battery energy storage inverters, variable-speed pumped hydro inverter, high-voltage direct current (HVDC) converters, static synchronous compensators (STATCOM), static VAR compensators (SVC), and other inverter/converter connected FACTS devices, as these technologies are also connected to the grid via a power electronic interface.
- Inverter-Based Resource examples include type 3 wind, type 4 wind, solar photovoltaic, battery energy storage, and variable-speed pumped hydro. There is a desire by the SDT to maintain a precedent that IBRs are considered “generating resources”, so the IBR term includes the phrase “primarily supplies active power”. Therefore, an HVDC system or a transmission-connected FACTS device (STATCOM, SVC, etc.) would not be considered an IBR.
- NERC Glossary terms apply to use in NERC Reliability Standards. NERC has a different focus than IEEE. "Power Electronic Device" was chosen as an alternative to the IEEE term "IBR unit" to differentiate the two terms.
- There is a need to distinguish between the individual “device” and the “resource/facility” as a whole, in order to allow the requirement language to be applied at device level or facility level. Hence, the two definitions for PED and IBR. The phrase “IBR plant/facility" refers to a facility in the common meaning.
- Battery energy storage system (BESS) will be considered as a PED/IBR independent of whether or not the device is operating in the charging or discharging 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~~**second** draft of the proposed standard **being posted** for a formal 45-day comment period **and additional ballot**.

| 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 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal or informal comment period with additional ballot | ~~February –~~ April **– June** 2023 |
| 10-day final ballot | ~~May~~**July** 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 of Real and Reactive Power Capability for BES Facilities

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

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

4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1** Generator Owner

   **4.1.2** Transmission Owner

   **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 resource identified through Inclusion I2 of the BES definition.

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

   **4.2.3** 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** **High-voltage direct current (**HVDC**)** terminal equipment including:

   **4.2.5.1** Voltage source converter (VSC).

   **4.2.6** **Facilities meeting an exclusion of the BES definition are exempt as an applicable Facility.**

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

## B. Requirements and Measures

**R1.** Each Generator 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]*

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

**1.2.** Verify the Reactive Power capability of its applicable Facilities in accordance with Attachment 1.

**1.3.** Submit the following information, in accordance with Attachment 2, to the Transmission Planner within 30 calendar days after the verification date~~:~~**. The verification date, as specified in Attachment 2, should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.**

**1.3.1.** ~~One-line~~**Simplified one-line** diagram representing the **applicable** Facility;

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

**1.3.3.** Documentation ~~showing the engineering basis,~~**of the underlying assumptions, design criteria, and methods for the chosen** verification methodology ~~and/or applicable data for the verification method~~**from Attachment 1**.

**M1.** Each Generator Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner 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~~**, in accordance with** Attachment 2**,** to the Transmission Planner within 30 calendar days after the verification date~~:~~**. The verification date, as specified in Attachment 2, should represent the date that the engineering review or engineering analysis is complete. The verification date is the basis of the recurring periodicity.**

**2.3.1.** ~~One-line~~**Simplified one-line** diagram representing the **applicable** Facility;

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

**2.3.3.** Documentation ~~showing the engineering basis,~~**of the underlying assumptions, design criteria, and methods for the chosen** verification methodology ~~and/or applicable data for the verification method~~**from Attachment 1**.

**M2.** Each Transmission Owner shall have evidence that it verified Real Power and Reactive Power capability of each **applicable** Facility, such as completed attachments or summary report(s); and have evidence that it submitted the information within 30 calendar days after the verification date to its Transmission Planner in accordance with Requirement R2.

**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 **to the submitter** within 90 calendar days ~~containing~~**from receiving each submission. The written response shall contain** one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

- Notification that the Transmission Planner has **reviewed the information and 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 **reviewed the information and 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~~**from receiving a notification. The written response shall contain** one of the following: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

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

**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 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.
- Each Generator Owner and Transmission Owner shall keep data or evidence of Requirement R4 for a rolling 12 month period.

**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 applicable entity provided all items in Requirement R1 **Part 1.3**, but did so between 31 and 90 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 3, but did so between ~~10 years (~~120 calendar months~~)~~ and 126 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days. | The applicable entity provided all items in Requirement R1 **Part 1.3**, but did so between 91 and 180 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power **capability in Part 1.1 and 1.2**, but failed to include the information required in Requirement R1, Part 1.3.1.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar | The applicable entity provided all items in Requirement R1 **Part 1.3**, but did so between 181 and 270 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power **capability in Part 1.1 and 1.2**, but failed to include the information required in Requirement R1, Part 1.3.3.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar | The applicable entity provided all items in Requirement R1 **Part 1.3**, but did so greater than 270 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power **capability in Part 1.1 and 1.2**, but failed to include the information required in Requirement R1, Part 1.3.2.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power capability **in Part 1.1 and 1.2,** per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days. |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | days. | days. | OR<br>The applicable entity failed to verify the Real and/or Reactive Power capability in Part 1.1 and 1.2. |
| **R2.** | The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 31 and 90 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did between ~~10 years (~~120 ~~calendar months)~~ and 126 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 181 and 270 calendar days. | The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 91 and 180 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.1.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so between 127 and 132 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power | The applicable entity provided all items in Requirement R2 Part 2.3, but did so between 181 and 270 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.3.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so between 133 and 138 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power | The applicable entity provided all items in Requirement R2 Part 2.3, but did so greater than 270 calendar days after the verification date.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, but failed to include the information required in Requirement R2, Part 2.3.2.<br>OR<br>The applicable entity verified the Real and Reactive Power capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 3, but did so in more than 138 calendar months.<br>OR<br>The applicable entity verified the Real and Reactive Power |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 271 and 360 calendar days. | capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so between 361 and 450 calendar days. | capability in Part 2.1 and 2.2, per Attachment 1 Section 1 Item 2, 4, or 5, but did so in more than 450 calendar days.<br>OR<br>The applicable entity failed to verify the Real and/or Reactive Power capability in Part 2.1 and 2.2. |
| **R3.** | The Transmission Planner provided a written response to the submitter, but it was provided between 91 to 120 calendar days after receiving the verified model information. | 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. | 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 Planner failed to provide a written response to the submitter.<br>OR<br>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 120 calendar days after receiving a notification of technical concern. | The applicable entity provided a written response to its Transmission Planner, but it was provided between 121 to 150 calendar days after receiving a notification of technical concern. | The applicable entity provided a written response to its Transmission Planner, but it was provided between 151 to 180 calendar days after receiving a notification of technical concern. | The applicable entity failed to provide a written response to its Transmission Planner.<br>OR<br>The applicable entity provided a written response to its Transmission Planner, but it was provided greater than 180 calendar days after receiving a |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | notification of technical concern. |

## D. Regional Variances

None.

## E. Associated Documents

~~None.~~

Reliability Guideline Power Plant Model Verification and Testing for Synchronous Machines, July 2018.

NATF Reporting and Verification of Generating Unit Reactive Power Capability for Synchronous Machines Reference, September 2020.

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | 12/1/2005 | 1. Changed tabs in footer.<br>2. Removed comma after 2004 in "Development Steps Completed," #1.<br>3. Changed incorrect use of certain hyphens (-) to "en dash" (–) and "em dash (—)."<br>4. Added "periods" to items where appropriate.<br>5. Changed apostrophes to "smart" symbols.<br>6. Changed "Timeframe" to "Time Frame" in item D, 1.2.<br>7. Lower cased all instances of "regional" in section D.3.<br>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-025-3 Attachment 1

## Section I. Periodicity of verification:

The periodicity to verify the Real and Reactive Power capability 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~~**120 calendar months** from the last verification date~~.~~**, unless it meets the following condition:**
   - **The Facility has been on a planned or unplanned outage of 180 days or greater, which overlaps its scheduled verification date. Verify the applicable Facility within 180 calendar days of its return to service date.**
4. 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 increase or decrease of the nameplate rating and is expected to last more than 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.~~

## Section II. Verification specifications for applicable Facilities:

1. For individual devices or generators greater than 20 MVA (gross nameplate rating) perform verification on an individual basis.
2. For individual devices or generators 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~~**Identify on the** one-line diagram ~~shall designate~~ where the composite capability curve created in Section II, Items 6-8 is represented.
   - 3.1. The **simplified** one-line **diagram** representing the Facility shall ~~include~~**represent** all auxiliary equipment expected to be in-service for normal operation, including dynamic and static reactive devices and auxiliary load, the **generator**

**step-up (**GSU**)**, and/or system interconnection transformer(s), 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 **Real and Reactive Power** capability for all equipment expected to be in-service for normal operation. The engineering ~~review~~**analysis** or engineering ~~analysis~~**review documentation** shall include **the** underlying assumptions, design criteria, and methods used to create the ~~Facility~~**Facility's composite** 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~~**Facility** 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~~**Facility** capability~~.~~**; or**

   - **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.**

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 **nameplate** steady-state Real Power and Reactive Power capability curve, or the synchronous condenser **nameplate** steady-state Reactive Power capability curve, provided by the equipment manufacturer. **If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.**

      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~~**nameplate** 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.

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:

[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.

8.1. The HVDC **nameplate** steady-state Real Power and Reactive Power capability curve, or the FACTS device steady-state Reactive Power capability, provided by the equipment manufacturer. **If the equipment manufacturer curve is not available, the curve shall be derived using the best available data.**

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~~**nameplate** 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.

2. 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. Refer to the associated labels depicted in the one-line diagram created in Section II, Item ~~4~~**3**. 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~~**Facility** voltage~~ regulating~~**/Reactive power control** equipment is in ~~automatic voltage regulating~~**the normal** mode **of operation**.

6. For an applicable Facility with Real Power capability, **not meeting the criteria of Section III, Part 7, 8 or 9,** 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;
   - 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.

[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.

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.

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 capability under less restrictive system voltages. 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.

# 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
  - ~~•~~ **and associated** ~~Section III: Associated~~ PQ data table
- Section ~~IV~~**III**: 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.~~

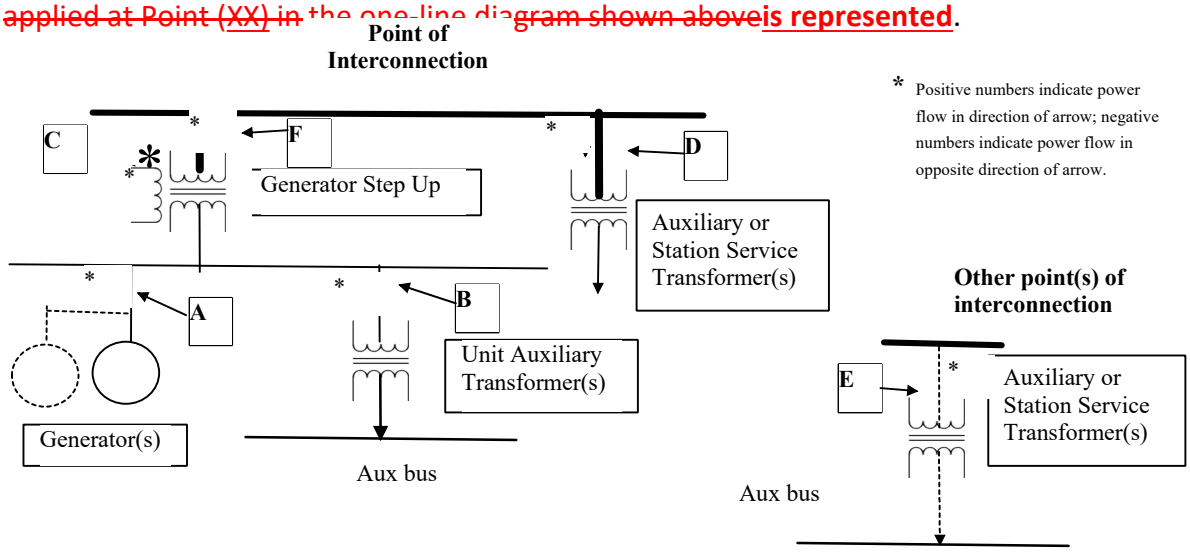
**An example report is provided below. The report may vary based on the Facility being represented.**

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

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

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

**Identify on the one-line diagram where the** ~~The~~ composite capability curve ~~provided below is applied at Point (XX) in the one-line diagram shown above~~**is represented**.



Section II. Provide composite capability curve as defined in Attachment 1, Section II**, with associated PQ curve data table.**

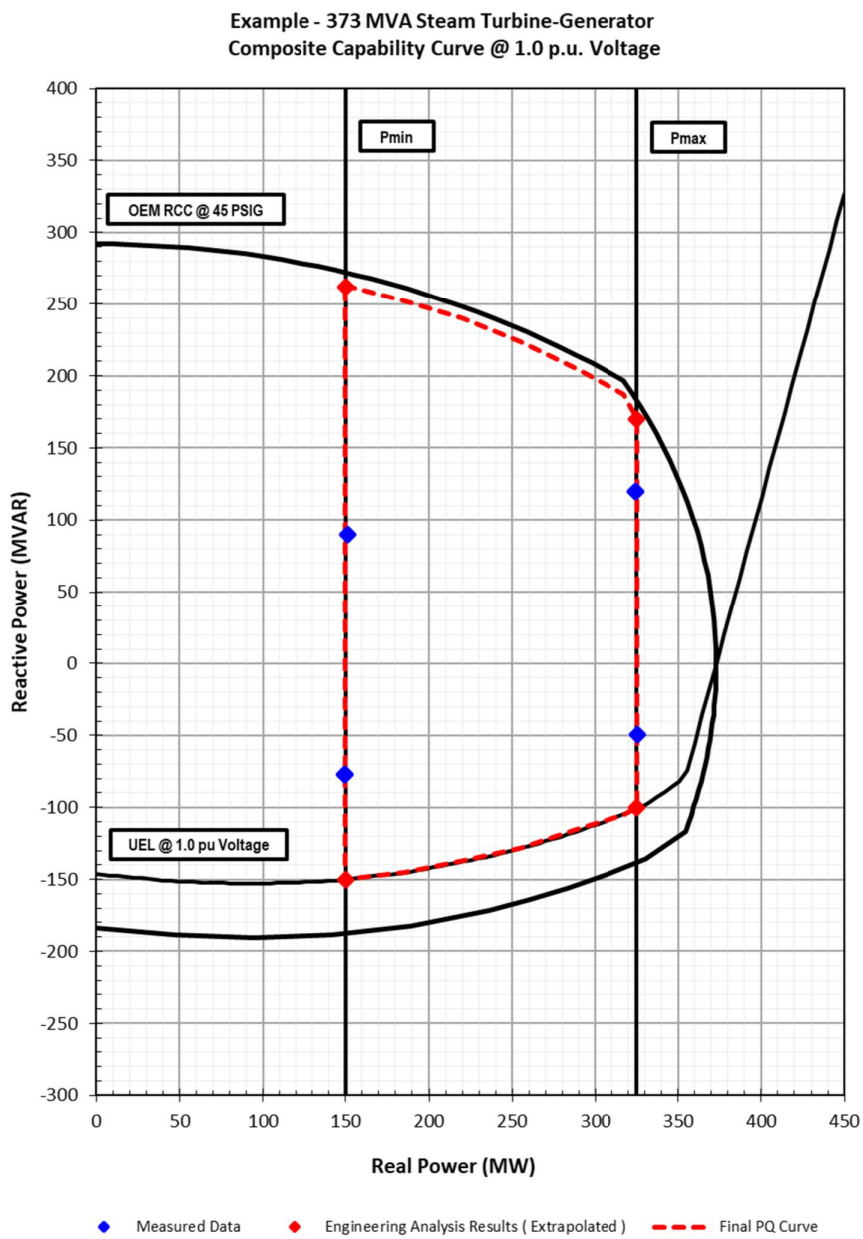



**Figure 1: Example Composite Capability Curve for Synchronous Generator**

~~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 |

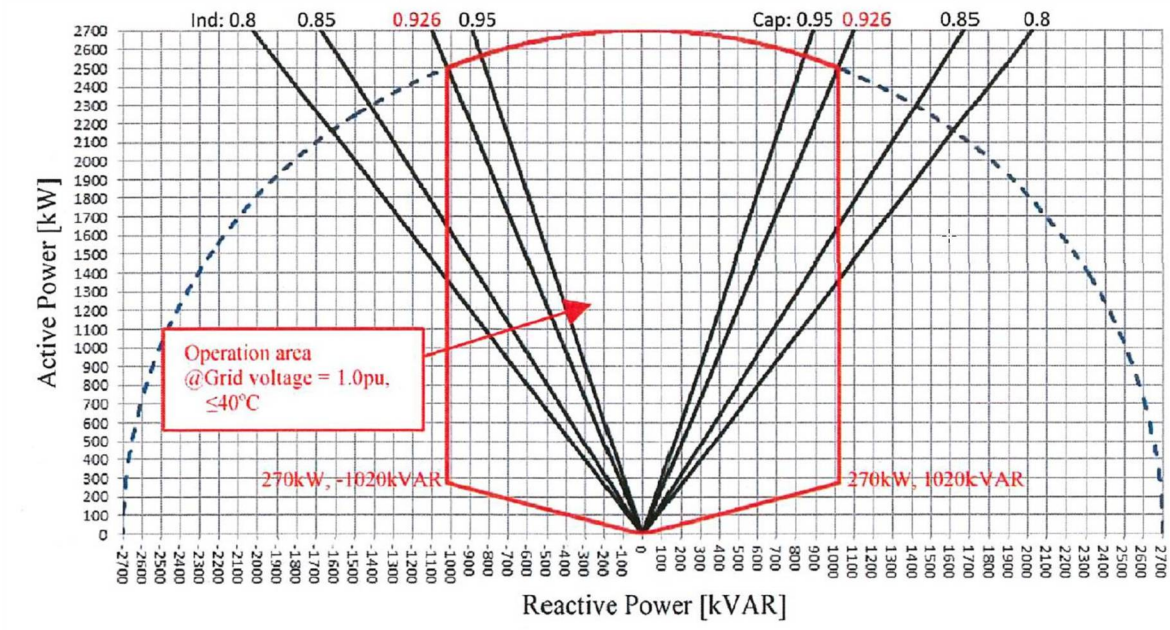



**Figure 2: Example Composite Capability Curve for IBR ~~Facility~~Unit**

## PQ Curve Data Table (template)

| Description | **Pmax** (MW) | **Qmax** (MVAR) | **Qmin** (MVAR) | **Qmax** Limiting Factor | **Qmin** Limiting Factor |
|---|---|---|---|---|---|
| Pmin | | | | | |
| Pmin + (0.20*Range)<br>Range = (~~$P_{max}$~~**Pman** - Pmin) | | | | | |
| Pmin + (0.40*Range) | | | | | |
| Pmin + (0.60*Range) | | | | | |
| Pmin + (0.80*Range) | | | | | |
| Pmax | | | | | |
| Additional data points such as breakpoints are optional. | | | | | |

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

Section ~~IV~~**III**. Supplemental documentation of ~~engineering basis and~~ verification methodology**.**

# MOD-~~025~~-025-3 Attachment 3

Data Table and Summary of Staged Test or Operational Data

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 is reported.

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

**Plant:** **Unit No.:**

Check all that apply:

☐ Over-excited Maximum Load Reactive Power Verification

☐ Under-excited 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

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: | | | | |

Summary of Test / Operational Data

- Date of Staged Test (or oldest Date of Operational Data): _____
- Start Time _____, End Time _____, Staged Test or Operational Data _____
- 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 cooling gas pressure at time of test (if applicable) _____
- If the staged test/operational data did not reach capability curve (D-curve), describe the limiting factor.

Testing Remarks:

| **Summary report:**<br>**Litera Compare for Word 11.3.1.3 Document comparison done on 4/20/2023 6:46:10 PM** | |
|---|---|
| **Style name:** NERC Standards | |
| **Intelligent Table Comparison:** Active | |
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| **Modified filename:** MOD-025-3 Draft 2.0.docx | |
| **Changes:** | |
| **Add** | 128 |
| ~~Delete~~ | 80 |
| ~~Move From~~ | 5 |
| **Move To** | 5 |
| **Table Insert** | 1 |
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| **Table moves to** | 0 |
| ~~Table moves from~~ | 0 |
| Embedded Graphics (Visio, ChemDraw, Images etc.) | 0 |
| Embedded Excel | 0 |
| Format changes | 0 |
| **Total Changes:** | 220 |

# 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~~**second** draft of the proposed standard **being posted** for a formal 45-day comment period **and additional ballot**.

| 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 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal or informal comment period with additional ballot | ~~February –~~ April **– June** 2023 |
| 10-day final ballot | ~~May~~**July** 2023 |
| Board adoption | August **or December** 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-019-3

3. **Purpose:** To verify coordination of generating unit or Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions.

4. **Applicability:**

   **4.1. Functional Entities**

   **4.1.1** Generator Owner

   **4.1.2** Transmission Owner

   **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 resource identified through Inclusion I2 of the BES definition.

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

   **4.2.3 Individual synchronous condenser greater than 20 MVA (gross nameplate rating) directly connected to the BES.**

   ~~**4.2.3** Dynamic reactive resources identified through Inclusion 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,~~**greater than 75 MVA (gross nameplate rating)** 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]

[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.

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

**4.2.5** Any Blackstart Resource.

**4.2.6** **Facilities meeting an exclusion of the BES definition are exempt as an applicable Facility.**

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

## B. Requirements and Measures

**R1.** ~~At a maximum of every six calendar years, each~~**Each** Generator Owner and Transmission Owner with applicable Facilities shall coordinate[3] the voltage regulating system controls, with the applicable equipment capabilities and settings of the applicable ~~protective~~**Protection System devices and** 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.** 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:

**1.1.1.** The in-service limiter functions[~~5~~4] are set to operate before the protective functions of the applicable Facility in order to avoid disconnecting the generator unnecessarily.

**1.1.2.** 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.

**1.2.** For IBR generating Facilities, assuming the voltage control mode[5] 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

[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~~**Protection System as-left** settings shall be utilized in **compliance evidence for** a protection and control coordination study.

[~~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~~4] Limiter functions that are installed and activated on the generator or synchronous condenser.

[5] **For an IBR generating Facility without a voltage control mode capability, coordination should be performed assuming the normal operation control mode, and R1.2.1. and R1.2.2. would not apply.**

[6] IBR unit ~~includes the inverter, converter, or wind turbine generator~~**as defined by IEEE Std. 2800**.

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 **the** 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~~**will** include dated documentation that demonstrates the coordination was performed.

**R2.** Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings changes that will affect the coordination described in Requirement R1~~; and update associated~~**. Associated** coordination documentation **shall be updated** 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;
- Protective function settings or component changes;
- IBR unit, synchronous generator**,** or synchronous condenser equipment capability changes;
- IBR unit, synchronous generator**,** or synchronous condenser step-up transformer changes;
- IBR unit control system firmware or settings changes; or
- ~~Power~~**IBR generating Facility power** plant controller firmware or settings changes.

**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~~**will** include dated documentation that demonstrates Requirement R2 has been met.

# C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Generator Owner and Transmission owner shall keep data or evidence of Requirement R1 of the most recent coordination study.
   - The Generator Owner and Transmission Owner shall 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.

## 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, control functions, and protection specified in Requirement R1 between 6 years (72 months) and 76 months after the previous coordination.~~ | ~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 77 and 81 months after the previous coordination.~~ | ~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 between 82 and 86 months after the previous coordination.~~ | ~~The Generator Owner or Transmission Owner coordinated equipment capabilities, control functions, and protection specified in Requirement R1 more than 86 months after the previous coordination.~~<br>~~OR~~<br>The Generator Owner or Transmission Owner failed to coordinate equipment capabilities, limiters, and protection as specified in Requirement R1. |
| **R2.** | The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 91 and 120 calendar days after return to in-service date. | The Generator Owner or Transmission Owner updated associated coordination documentation as specified in Requirement R2 between 121 and 150 calendar days after return to in-service date. | The Generator Owner or Transmission Owner updated 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 update associated coordination documentation as specified in Requirement R2 within ~~151~~**181** calendar days after return to in-service date.<br>OR<br>The Generator Owner or Transmission Owner failed to |

*[Link-to-previous setting changed from on in original to off in modified.].*

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | coordinate equipment capabilities, limiters, and protection specified in Requirement R1 prior to ~~the~~ implementing a change in equipment or settings that affected the coordination. |

## D. Regional Variances

None.

## E. 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"

**"IEEE Std 2800-2022 IEEE Standard for Interconnection and Interoperability of Invert-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems"**

*[Link-to-previous setting changed from on in original to off in modified.].*

## 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:<br>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 |

# Attachment 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.

A. Synchronous generation equipment capabilities, control functions, and protective functions, which shall be coordinated if enabled, include but are not limited to:

- Synchronous generator/condenser reactive capabilities;
- Field over-excitation limiter and associated protective function;
- Field under-excitation limiter and associated protective function;
- Volts per hertz limiter and associated protective function;
- Stator over-voltage protection system settings;
- 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 **and associated control function**;
- Transformer undervoltage protective function **and associated control function**;
- Transformer volts per hertz capability ~~and~~ protective function **and associated control function**;
- Collector bus overvoltage protective function **and associated control function**;
- Collector bus undervoltage protective function **and associated control function**;
- Reactive compensating devices voltage control functions **and associated control function**;
- Reactive compensating devices voltage protective function **and associated control function**;
- Collector feeder phase overvoltage protective function **and associated control function**;
- Collector feeder phase undervoltage protective function **and associated control function**;
- Collector feeder overcurrent limiter~~;~~
- **and associated** ~~IBR unit phase lock loop~~ protective function;

- IBR unit overcurrent limiter **and associated protective function**;
- IBR unit momentary cessation (cease current injection) protective function;
- IBR unit phase overvoltage protective function **and associated control function**;
- IBR unit phase undervoltage protective function **and associated control function**; and
- IBR unit phase overcurrent protective function **and associated control function**.

| **Summary report:**<br>**Litera Compare for Word 11.3.1.3 Document comparison done on 4/20/2023 7:05:12 PM** | |
|---|---|
| **Style name:** NERC Standards | |
| **Intelligent Table Comparison:** Active | |
| **Original filename:** PRC-019-3 Draft 1.0.docx | |
| **Modified filename:** PRC-019-3 Draft 2.0.docx | |
| **Changes:** | |
| **Add** | 58 |
| ~~Delete~~ | 44 |
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| **Move To** | 0 |
| **Table Insert** | 1 |
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| ~~Table moves from~~ | 0 |
| Embedded Graphics (Visio, ChemDraw, Images etc.) | 0 |
| Embedded Excel | 0 |
| Format changes | 0 |
| **Total Changes:** | 104 |

# 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~~ third 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 – January 13, 2023 |
| 45-day formal comment period with additional ballot | May 10 – June 23, 2023 |
| 45-day formal comment period with additional ballot | September 22 – November 6, 2023 |
| 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:** Generator Operation for Maintaining Network Voltage Schedules

2. **Number:** VAR-002-5

3. **Purpose:** To ensure Bulk Electric System generating resource(s) ~~and dispersed power producing resources~~ provide reactive support and voltage control, within generating ~~Facility~~ resource capabilities, in order to protect equipment, and maintain Reliable Operation of the Interconnection.

4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1.** Generator Operator

   **4.1.2.** Generator Owner

   ~~**4.2. Facilities:** For the purpose of this standard, "applicable Facility" will mean any generating Facility as defined by the Bulk Electric System.~~

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

## B. Requirements and Measures

**R1.** The Generator Operator shall operate each ~~applicable Facility~~generating resource(s) connected to the interconnected ~~transmission~~ Transmission ~~system~~ System in the automatic voltage control mode (with its automatic voltage regulator (AVR~~) or volt/VAR controller(s)~~[1] in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the ~~applicable Facility~~generating resource(s) is 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 ~~applicable Facility~~generating resource(s) is being operated in start-up[2], shutdown[3], or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
- That the ~~applicable Facility~~generating resource(s) 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.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate ~~an~~ a ~~applicable Facility~~generating resource(s) in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If ~~an~~ a ~~applicable Facility~~generating resource(s) 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 ~~an~~ a ~~applicable Facility~~generating resource(s) is exempted from 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.

**R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the ~~applicable Facility~~generating resource(s) voltage or Reactive Power schedule[4] (within each generating Facility's capabilities[5]) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or

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[1] For dispersed power producing resources identified through inclusion I4 of the Bulk Electric System definition, the automatic voltage regulator (AVR) refers to the voltage & reactive power control system controlling and coordinating plant voltage.~~For an aggregate generating plant, the volt/VAR controller includes the voltage & reactive power control system controlling and coordinating plant voltage.~~

[2] Start-up is deemed to have ended when the ~~applicable Facility~~generating resource(s) is ramped up to its minimum continuously sustainable Load and the ~~applicable Facility~~generating resource(s) is prepared for continuous operation.

[3] Shutdown is deemed to begin when the ~~applicable Facility~~generating resource(s) is ramped down to its minimum continuously sustainable Load and the ~~applicable Facility~~generating resource(s) is prepared to go offline.
[4] 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.
[5] Generating ~~Facility~~ resource(s) 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 ~~an~~ a ~~applicable Facility~~generating resource(s) is operating in manual control, Reactive Power capability may change, based on stability considerations.

Reactive Power schedule provided by the Transmission Operator. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

**2.1.** When ~~an~~ a ~~applicable Facility~~generating resource(s)'s AVR ~~or volt/VAR controller(s)~~ is out of service or the ~~generator~~ applicable Facility does not have an AVR, the Generator Operator shall use an alternative method to control the ~~generator~~ applicable Facility reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator or if no other method of control is available, notify the Transmission Operator as soon as becoming aware of the condition.

**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 to the voltage point being monitored by the Generator Operator.

**M2.** In order to identify when ~~an~~ a ~~applicable Facility~~generating resource(s) is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility. The Generator Operator will have evidence to show that the ~~applicable Facility~~generating resource(s) maintained the voltage or Reactive Power schedule provided by the Transmission Operator 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 ~~an~~ a ~~applicable Facility~~generating resource(s)'s AVR ~~or volt/VAR controller(s)~~ is out of service or the ~~applicable Facility~~generating resource(s) does not have an AVR, a Generator Operator shall 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 or evidence of notification to the Transmission Operator if no other method of control is available.

For Part 2.2, the Generator Operator will have evidence that it complied with the Transmission Operator's instructions to modify its voltage or provided an explanation 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 will demonstrate the methodology for converting the scheduled voltage to the voltage point being monitored by the Generator Operator.

**R3.** Each Generator Operator shall notify its associated Transmission Operator, in a mutually-~~agreeable~~ agreed communication ~~criteria~~[6]method, within 30 minutes of status change of its AVR or within 30 minutes of becoming aware ~~its associated Transmission Operator~~ of ~~a~~ an ~~status or~~ unexpected functionality change of ~~applicable~~ its AVR, ~~volt/VAR controller(s),~~ power system stabilizer, or alternative voltage controlling device. ~~which degrades or restores from degradation its ability to automatically control voltage. Status or functionality change notifications shall be made within 30 minutes of such change.~~ If the status or functionality has been restored within 30 minutes, 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.** ~~The~~ Each Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of status change of its AVR or within 30 minutes of becoming aware of an unexpected functionality change ~~within 30 minutes of the change~~ identified in Requirement R3~~ and evidence of the mutually-agreeable criteria 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, no notification is necessary.

**R4.** Each Generator Operator shall notify its associated Transmission Operator, in a mutually-agreeable communication ~~criteria~~method, ~~its associated Transmission Operator~~ within 30 minutes of becoming aware of a ~~-~~reactive capability change ~~in reactive capability that degrades or restores from degradation and exceeds the threshold for notification~~ due to factors other than those specified in Requirement R3 at the generating resource(s). Where the Transmission Operator has specified a reactive capability threshold, the Generator Operator shall report reactive capability changes that create degradation or restores from degradation. 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]*

**M4.** ~~The~~ Each Generator Operator shall 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, as necessary, with the Transmission Operator to identify a mutually- agreeable criteria, such as any of the following: emails, voltage schedule documentation, or reliability data specification.~~

**R5.** The Generator Owner for each ~~applicable Facility~~generating resource(s) 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: Operations Planning]*

**5.1.** For generator step-up[6] and auxiliary transformers[7] with primary voltages equal

[6] Generator step-up and auxiliary transformers would be owned and maintained by the Generator Owner.

[7] For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement

to or greater than the generator terminal voltage:

**5.1.1.** Tap settings.

**5.1.2.** Available tap ranges.

**5.1.3.** Impedance data.

**M5.** The Generator Owner for each ~~applicable Facility~~generating resource(s) shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its

~~[6] Mutually-agreeable format for VAR-002-5 - notification should include the communication method (e.g., voice, data, email, etc.) and the threshold of degradation an applicable Facility.~~

(Requirement R5 and its subparts) applies only to those transformers that have at least one winding at a voltage of 100 kV or above.

step-up and auxiliary transformers as required in Requirement R5, Part 5.1.1 through Part 5.1.3 within 30 calendar days.

**R6.** After consultation with the Transmission Operator regarding necessary generator owned step-up transformer tap changes, the Generator Owner for each ~~applicable Facility~~generating resource(s) 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, a regulatory requirement, or a statutory requirement. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**6.1.** If the applicable Generator Owner for each ~~applicable Facility~~generating resource(s) cannot comply with the Transmission Operator's specifications, the Generator Owner for each ~~applicable Facility~~generating resource(s) shall notify the Transmission Operator and shall provide the technical justification.

**M6.** The ~~applicable Facility~~generating resource(s) shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation in accordance with Requirement R6. The ~~applicable Facility~~generating resource(s) shall 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.

**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 Generator Owner and Generator Operator 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 Generator Owner for each ~~applicable Facility~~generating resource(s) shall keep its latest version of documentation on its step-up and auxiliary transformers.

~~The Generator Operator for each applicable Facility shall keep its latest version of documentation on its step-up and auxiliary transformers.~~

The Generator Operator for each ~~applicable Facility~~generating resource(s) shall retain evidence of Requirements R1, R2, R3 and R4 for three calendar years.

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

## Violation Severity Levels

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1.** | N/A | N/A | N/A | Unless exempted, the Generator Operator did not operate each generator and 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. |
| **R2.** | N/A | N/A | The Generator Operator did maintain voltage or Reactive Power as instructed by the Transmission Operator.<br>AND,<br>The Generator Operator did make the necessary notifications required by the Transmission Operator. | The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator.<br>AND<br>The Generator Operator did not make the necessary notifications required by the Transmission Operator. |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | BUT<br>The Generator Operator did not have a conversion methodology when it monitored voltage at a location different from the schedule provided by the Transmission Operator. | OR<br>The Generator Operator did not have an operating AVR ~~or volt/VAR controller(s)~~, and did not use an alternative method for controlling voltage or provide notification to the Transmission Operator if no alternative method of control was available.<br>OR<br>The Generator Operator did not modify voltage when directed, and did not provide any explanation. |
| **R3.** | N/A | N/A | N/A | The Generator Operator did not make the required notification within 30 minutes of the status or functionality change. |
| **R4.** | N/A | N/A | N/A | The Generator Operator did not make the required notification within 30 minutes of becoming aware |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | of the capability change. |
| **R5.** | N/A | N/A | The Generator Owner for each ~~applicable Facility~~generating resource(s) failed to provide its associated Transmission Operator and Transmission Planner one of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3. | The Generator Owner for each ~~applicable Facility~~generating resource(s) 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. |
| **R6.** | N/A | N/A | N/A | The Generator Owner for each ~~applicable Facility~~generating resource(s) did not ensure the tap changes were made according to the Transmission Operator's specifications.<br>OR<br>The Generator Owner for each ~~applicable Facility~~generating resource(s) failed to perform the tap changes, and the Generator Owner for each ~~applicable Facility~~generating resource(s) did not provide technical justification for why it could not comply with the Transmission Operator specifications. |

## D. Regional Variances

None.

## E. 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, 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 |
| 1.1b | 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 with VAR001-2, R4. FERC Order issued approving VAR002-2b. | Revised |
| 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. | |
| 4 | 8/27/2014 | Revised under Project 2014-01 to clarify applicability of Requirements to BES dispersed power producing resources. | Revised |
| 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 | 6/14/2017 | Project 2016-EPR-02 errata recommendations. | Errata |
| 4.1 | 8/10/2017 | Adopted by the NERC Board of Trustees. | Errata |
| 4.1 | 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 |

# Standard Development Timeline

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

## Description of Current Draft

This is the initial draft of the proposed standard.

| Completed Actions | Date |
|---|---|
| Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting | March 6, 2016 |
| SAR posted for 2016-02 TOCC comment | March 23 – April 21, 2016 |
| SC Accepted the 2016-02 TOCC SAR | July 20, 2016 |
| 45-day formal comment period with ballot | September – November 2023 |

| Anticipated Actions | Date |
|---|---|
| Final Ballot TOCC | December 2023 |
| Board adoption | December 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):

**Control Center** - One or more ~~facilities~~ rooms where a responsible entity hosts ~~hosting~~ operating personnel ~~that~~ to monitor and control the Bulk Electric System (BES) in real-time, as described below, ~~to perform the reliability tasks,~~ including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.~~their associated data centers, of:~~

1) Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;~~,~~

2) Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;~~,~~

3) Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for ~~t~~Transmission Facilities at two or more locations;

4) ~~,~~Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

5) Operating personnel of a Generator Operator who have the capability to electronically control ~~for~~ generation Facilities at two or more locations in real-time.

## A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~Y

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

**4.1.1. Balancing Authority**

**4.1.2. Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

**4.1.2.1.** Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

**4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.1.2.2.** ~~Each Special Protection System or~~ Remedial Action Scheme (RAS) where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.1.2.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.1.3. Generator Operator**

**4.1.4. Generator Owner**

~~**Interchange Coordinator or Interchange Authority**~~

**4.1.5. Reliability Coordinator**

**4.1.6. Transmission Operator**

**4.1.7. Transmission Owner**

**4.2.** **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

**4.2.1. Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

**4.2.1.1.** Each UFLS or UVLS System that:

**4.2.1.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

**4.2.1.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

**4.2.1.2.** ~~Each Special Protection System or Remedial Action Scheme~~RAS where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.3.** Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

**4.2.1.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

**4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers**:

All BES Facilities.

**4.2.3. Exemptions:** The following are exempt from Standard CIP-002-~~5.1a~~Y:

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

**4.2.3.2.** Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

**4.2.3.3.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

**4.2.3.4.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

**5. Effective Dates:** See "Project 2021-03 CIP-002 Transmission Owners Control Centers Implementation Plan"

~~1. **24 Months Minimum –** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

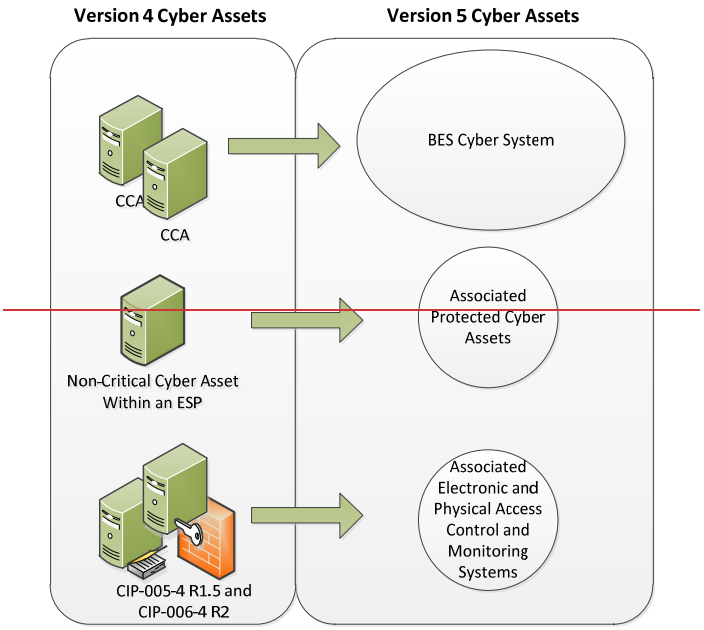
~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

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

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~




~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System~~

~~boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

**~~Reliable Operation of the BES~~**

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

**~~Real-time Operations~~**

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

**~~Categorization Criteria~~**

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

**~~Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems~~**

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic~~

~~Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS") –** Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS") –** Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA") –** Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

## B. Requirements and Measures

**R1.** Each Responsible Entity shall implement a process that considers each of the following assets for purposes of ~~p~~Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

**i.** Control Centers and backup Control Centers;
**ii.** Transmission stations and substations;
**iii.** Generation resources;
**iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
**v.** ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES; and
**vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

**1.1.** Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

**1.2.** Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

**1.3.** Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

**M1.** Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

**R2.** The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**2.1** Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

**2.2** Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

**M2.** Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

## C. Compliance

**1. Compliance Monitoring Process:**

**1.1. Compliance Enforcement Authority:**

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

**1.2. Evidence Retention:**

The following evidence retention 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~~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:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

**1.3. Compliance Monitoring and ~~Assessment Processes~~Enforcement Program:**

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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

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

- ~~None~~

## ~~2. Table of Compliance Elements~~ Violation Severity Levels

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| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-~~5.1a~~Y) | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1** | **Operations Planning** | **High** | For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1;<br>OR<br>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1;<br>OR<br>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber | For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1;<br>OR<br>For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1;<br>OR | For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1;<br>OR<br>For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1;<br>OR | For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1;<br>OR<br>For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1;<br>OR<br>For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-~~5.1a~~Y) | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.<br>OR<br>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber | For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly | For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;<br>OR<br>For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber ~~Assets~~Systems, more than 10 but less than or equal to 15 identified BES Cyber ~~Assets~~Systems have not been categorized or have been | Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.<br>OR<br>For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-~~5.1a~~Y) | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified. | categorized at a lower category.<br>OR<br>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10- high or medium BES Cyber Systems have not been identified. | incorrectly categorized at a lower category.<br>OR<br>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15- high or medium BES Cyber Systems have not been identified. | Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified;<br>OR<br>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified. |

| R # | Time Horizon | VRF | Violation Severity Levels (CIP-002-~~5.1a~~Y) | | | |
|---|---|---|---|---|---|---|
| | | | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R2** | **Operations Planning** | **Lower** | The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1)<br>OR<br>The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2) | The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1)<br>OR<br>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2) | The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1)<br>OR<br>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2) | The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)<br>OR<br>The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2) |

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Associated Documents

None.

# ~~CIP-002-5.1a~~Y ~~-~~ Attachment 1 – Impact Rating Criteria

~~Impact Rating Criteria~~

*The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*

**1. High Impact Rating (H)**

Each BES Cyber System used by and located at any of the following:

**1.1.** Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

**1.2.** Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

**1.3.** Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

**1.4** Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

**2. Medium Impact Rating (M)**

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

**2.1.** Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

**2.2.** Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

**2.3.** Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

**2.4.** Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

**2.5.** Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

| Voltage Value of a Line | Weight Value per Line |
|---|---|
| less than 200 kV (not applicable) | (not applicable) |
| 200 kV to 299 kV | 700 |
| 300 kV to 499 kV | 1300 |
| 500 kV and above | 0 |

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**2.6.** Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

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

**2.8.** Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

**2.9.** ~~Each Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

**2.10.** Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underframeset load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

**2.11.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

**2.12.** Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~ , operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H~~)~~) above~~.~~, with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

| Voltage Value of a BES Transmission Line | Weight Value per BES Transmission Line |
|---|---|
| <100 kV | 100 |
| 100 kV to 199 kV | 250 |
| 200 kV to 299 kV | 700 |
| 300 kV to 499 kV | 1300 |
| 500 kV and above | 0 |

Exclusion:
BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the "aggregate weighted value" calculation if they are part of a local system that is operated at less than 300kV, where the net export from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The net export is based on the hourly integrated values for the most recent 12-month period.

~~**2.12.**~~**2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing

Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

**3. Low Impact Rating (L)**

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

**3.1.** Control Centers and backup Control Centers.

**3.2.** Transmission stations and substations.

**3.3.** Generation resources.

**3.4.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

**3.5.** ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES.

**3.6.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

## ~~Guidelines and Technical Basis~~

### ~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

### ~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

| ~~Entity Registration~~ | ~~RC~~ | ~~BA~~ | ~~TOP~~ | ~~TO~~ | ~~DP~~ | ~~GOP~~ | ~~GO~~ |
|---|---|---|---|---|---|---|---|
| ~~Dynamic Response~~ | | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ |
| ~~Balancing Load & Generation~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ |
| ~~Controlling Frequency~~ | | ~~X~~ | | | | ~~X~~ | ~~X~~ |
| ~~Controlling Voltage~~ | | | ~~X~~ | ~~X~~ | ~~X~~ | | ~~X~~ |
| ~~Managing Constraints~~ | ~~X~~ | | ~~X~~ | | | ~~X~~ | |
| ~~Monitoring and Control~~ | | | ~~X~~ | | | ~~X~~ | |
| ~~Restoration~~ | | | ~~X~~ | | | ~~X~~ | |
| ~~Situation Awareness~~ | ~~X~~ | ~~X~~ | ~~X~~ | | | ~~X~~ | |
| ~~Inter-Entity coordination~~ | ~~X~~ | ~~X~~ | ~~X~~ | ~~X~~ | | ~~X~~ | ~~X~~ |

~~**Dynamic Response**~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~
  - ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

**~~Balancing Load and Generation~~**

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~

- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

**~~Controlling Frequency (Real Power)~~**

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

**~~Controlling Voltage (Reactive Power)~~**

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

**~~Managing Constraints~~**

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~
- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

**~~Monitoring and Control~~**

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

**~~Restoration of BES~~**

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

**~~Situational Awareness~~**

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

**~~Inter-Entity Coordination~~**

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

**~~Applicability to Distribution Providers~~**

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

**~~Requirement R1:~~**

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~**Attachment 1**~~

~~**Overall Application**~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~
- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~**High Impact Rating (H)**~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some~~

~~of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

**~~Medium Impact Rating (M)~~**

**~~Generation~~**

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

  ~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

  ~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~**Transmission**~~

~~*The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.*~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~

  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

  - ~~230 kV –> 700 MVA~~

  - ~~345 kV –> 1,300 MVA~~

  - ~~500 kV –> 2,000 MVA~~

  - ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

  - ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate~~

~~connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~
- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~
2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~

- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~

- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~

- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~

- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

  ~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~

- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

**~~Low Impact Rating (L)~~**

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

**~~Restoration Facilities~~**

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

  ~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

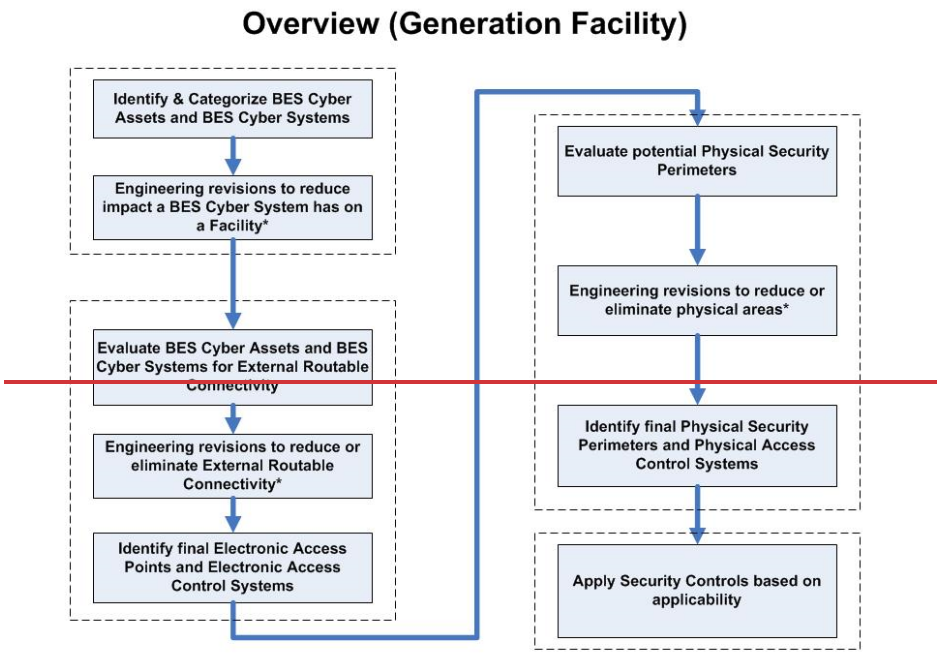
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~




* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

**~~Rationale:~~**

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

**~~Rationale for R1:~~**

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

**~~Rationale for R2:~~**

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.~~

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | 1/16/06 | R3.2 — Change "Control Center" to "control center." | 3/24/06 |
| 2 | 9/30/09 | Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.<br>Removal of reasonable business judgment.<br>Replaced the RRO with the RE as a Responsible Entity.<br>Rewording of Effective Date.<br>Changed compliance monitor to Compliance Enforcement Authority. | |
| 3 | 12/16/09 | Updated version number from -2 to -3. | Update |

| | | | |
|---|---|---|---|
| | | Approved by the NERC Board of Trustees. | |
| 3 | 3/31/10 | Approved by FERC. | |
| 4 | 12/30/10 | Modified to add specific criteria for Critical Asset identification. | Update |
| 4 | 1/24/11 | Approved by the NERC Board of Trustees. | Update |
| 5 | 11/26/12 | Adopted by the NERC Board of Trustees. | Modified to coordinate with other CIP standards and to revise format to use RBS Template. |
| 5.1 | 9/30/13 | Replaced “Devices” with “Systems” in a definition in background section. | Errata |
| 5.1 | 11/22/13 | FERC Order issued approving CIP-002-5.1. | |
| 5.1a | 11/02/16 | Adopted by the NERC Board of Trustees. | |
| 5.1a | 12/14/2016 | FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000. | |
| Y | TBD | | |

## ~~Appendix 1~~

| ~~Requirement Number and Text of Requirement~~ |
| --- |
| ~~CIP-002-5.1, Requirement R1~~<br>~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~<br>~~i. Control Centers and backup Control Centers;~~<br>~~ii. Transmission stations and substations;~~<br>~~iii. Generation resources;~~<br>~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~<br>~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~<br>~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~<br>~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~<br>~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~<br>~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~<br>~~Attachment 1, Criterion 2.1~~<br>~~2. Medium Impact Rating (M)~~<br>~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~<br>~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~ |

| ~~**Questions**~~ |
| --- |
| ~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~<br><br>~~The Interpretation Drafting Team identified the following questions in the RFI:~~<br><br>~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~<br>~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~<br>~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~ |
| ~~**Responses**~~ |
| ~~**Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?**~~<br><br>~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~<br><br>~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~<br><br>~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~ |

**~~Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~**

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.~~

**~~Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~**

~~The phrase applies to each discrete BES Cyber System.~~

# 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 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 |
| 45-day formal comment period with ballot –Phase 2 | 2/28/23 – 4/13/23 |
| 20-day formal comment period with additional ballot – Phase 2 | 8/24/23 – 9/12/23 |

| Anticipated Actions | Date |
|---|---|
| 8-day final ballot | 9/29/23 – 10/6/23 |
| Board adoption | October 2023 |

## A. Introduction

1. **Title: Operations Planning**

2. **Number: TOP-002-~~4~~5**

3. **Purpose:** To ensure that Transmission Operators and Balancing Authorities have plans for operating within specified limits.

4. **Applicability:**

   **4.1.** Transmission Operator

   **4.2.** Balancing Authority

5. **Effective Date:**

   See Implementation Plan.

6. **Background:**

   ~~See Project 2014-03 project page.~~

   See Project 2021-07 project page.

## B. Requirements and Measures

**R1.** Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M1.** Each Transmission Operator shall have evidence of a completed Operational Planning Analysis. Such evidence could include, but is not limited to dated power flow study results.

**R2.** Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M2.** Each Transmission Operator shall have evidence that it has an Operating Plan to address potential System Operating Limits (SOLs) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. Such evidence could include, but it is not limited to plans for precluding operating in excess of each SOL that was identified as a result of the Operational Planning Analysis.

**R3.** Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M3.** Each Transmission Operator shall have evidence that it notified entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in the plan(s). Such

evidence could include, but is not limited to dated operator logs, or ~~e-mail~~email records.

**R4.** Each Balancing Authority shall have an Operating Plan(s) for the next- day that addresses: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**4.1** Expected generation resource commitment and dispatch;

**4.2** Interchange scheduling;

**4.3** Demand patterns-; and

~~-~~**4.4** Capacity and energy reserve requirements, including deliverability capability.

**M4.** Each Balancing Authority shall have evidence that it has developed a plan to operate within the criteria identified. -Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

**R5.** Each Balancing Authority shall notify entities identified in the Operating Plan(s) cited in Requirement R4 as to their role in those plan(s). -*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M5.** Each Balancing Authority shall have evidence that it notified entities identified in the plan(s) cited in Requirement R4 as to their role in the plan(s). -Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

**R6.** Each Transmission Operator shall provide its Operating Plan(s) for next- day operations identified in Requirement R2 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M6.** Each Transmission Operator shall have evidence that it provided its Operating Plan(s) for next- day operations identified in Requirement R2 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

**R7.** Each Balancing Authority shall provide its Operating Plan(s) for next- day operations identified in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**M7.** Each Balancing Authority shall have evidence that it provided its Operating Plan(s) for next- day operations identified in Requirement R4 to its Reliability Coordinator. Such evidence could include, but is not limited to dated operator logs or ~~e-mail~~email records.

**R8.** Each Balancing Authority shall have an extreme cold weather Operating Process for its Balancing Authority Area, addressing preparations for and operations during extreme cold weather periods. The extreme cold weather Operating Process shall include, but is not limited to: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**8.1** A methodology for identifying an extreme cold weather period within each Balancing Authority Area;

**8.2** A methodology to determine an adequate reserve margin during the extreme cold weather period considering the generating unit(s) operating limitations in previous extreme cold weather periods that includes, but is not limited to:

**8.2.1** Capability and availability;

**8.2.2** Fuel supply and inventory concerns;

**8.2.3** Start-up issues;

**8.2.4** Fuel switching capabilities; and

**8.2.5** Environmental constraints.

**8.3** A methodology to determine a five-day hourly forecast during the identified extreme cold weather periods that includes, but is not limited to:

**8.3.1** Expected generation resource commitment and dispatch;

**8.3.2** Demand patterns;

**8.3.3** Capacity and energy reserve requirements, including deliverability capability; and

**8.3.4** Weather forecast.

**M8.** Each Balancing Authority shall have evidence that it has developed an extreme cold weather Operating Process in accordance with Requirement R8.

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority

1.2.1.1. As defined in the NERC Rules of Procedure,: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the NERCmandatory and enforceable Reliability Standards in their respective jurisdictions.

#### 1.3. Compliance Monitoring and Assessment Processes

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

#### 1.4. DataEvidence Retention

1.2. : The following evidence retention periodsperiod(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 CEA to retain specific evidence for a longer period of time as part of an investigation.

- Each Transmission Operator and Balancing Authority shall keep data or evidence to show compliance for each applicable Requirement for a rolling 90-calendar days period for analyses, the most recent 90-calendar days for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator or The Balancing Authority is found non-compliant, it shall keep information related to the non-retain the current Operating Process(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance until found compliant or the time period specified above, whichever is longer.

- The Compliance Enforcement Authority shall keepsince the last audit records and all requested and submitted subsequent audit records for Requirement R8.

#### 1.5. Additional Compliance Information

~~None.~~

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

## Violation Severity Levels

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1** | N/A | N/A | N/A | The Transmission Operator did not have an Operational Planning Analysis allowing it to assess whether its planned operations for the next day within its Transmission Operator Area exceeded any of its System Operating Limits (SOLs). |
| **R2** | N/A | N/A | N/A | The Transmission Operator did not have an Operating Plan to address potential System Operating Limit (SOL) exceedances identified as a result of the Operational Planning Analysis performed in Requirement R1. |
| **R3** | The Transmission Operator did not notify one impacted entity or 5% or less of the entities, whichever is greater identified in the | The Transmission Operator did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the | The Transmission Operator did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the | The Transmission Operator did not notify four or more entities or more than 15% of the impacted NERC identified in the Operating Plan(s) as to their role in the plan(s). |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | Operating Plan(s) as to their role in the plan(s). | Operating Plan(s) as to their role in the plan(s). | Operating Plan(s) as to their role in the plan(s). | |
| **R4** | The Balancing Authority has an Operating Plan, but it does not address one of the criteria in Requirement R4. | The Balancing Authority has an Operating Plan, but it does not address two of the criteria in Requirement R4. | The Balancing Authority has an Operating Plan, but it does not address three of the criteria in Requirement R4. | The Balancing Authority did not have an Operating Plan. |
| **R5** | The Balancing Authority did not notify one impacted entity or 5% or less of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s). | The Balancing Authority did not notify two entities or more than 5% and less than or equal to 10% of the impacted entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s). | The Balancing Authority did not notify three impacted entities or more than 10% and less than or equal to 15% of the entities, whichever is greater, identified in the Operating Plan(s) as to their role in the plan(s). | The Balancing Authority did not notify four or more entities or more than 15% of the impacted entities identified in the Operating Plan(s) as to their role in the plan(s). |
| **R6** | N/A | N/A | N/A | The Transmission Operator did not provide its Operating Plan(s) for next day operations as identified in Requirement R2 to its Reliability Coordinator. |
| **R7** | N/A | N/A | N/A | The Balancing Authority did not provide its Operating Plan(s) for next day operations as |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | | identified in Requirement R4 to its Reliability Coordinator. |
| R8 | N/A | The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address one of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3. | The Balancing Authority had an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods, but it did not address two of the Requirements or sub-Requirements of R8 Parts 8.1 through 8.3. | The Balancing Authority did not have an extreme cold weather Operating Process addressing preparations for and operations during extreme cold weather periods. |

## D. Regional Variances

None.

## E. Interpretations

None.

## F. Associated Documents

~~Operating Plan - An Operating Plan includes general Operating Processes and specific Operating Procedures. It may be an overview document which provides a prescription for an Operating Plan for the next-day, or it may be a specific plan to address a specific SOL or IROL exceedance identified in the Operational Planning Analysis (OPA). Consistent with the NERC definition, Operating Plans can be general in nature, or they can be specific plans to address specific reliability issues. The use of the term Operating Plan in the revised TOP/IRO standards allows room for both. An Operating Plan references processes and procedures which are available to the System Operator on a daily basis to allow the operator to reliably address conditions which may arise throughout the day. It is valid for tomorrow, the day after, and the day after that. Operating Plans should be augmented by temporary operating guides which outline prevention/mitigation plans for specific situations which are identified day-to-day in an OPA or a Real-time Assessment (RTA). As the definition in the Glossary of Terms states, a restoration plan is an example of an Operating Plan. It contains all the overarching principles that the System Operator needs to work his/her way through the restoration process. It is not a specific document written for a specific blackout scenario but rather a collection of tools consisting of processes, procedures, and automated software systems that are available to the operator to use in restoring the system. An Operating Plan can in turn be looked upon in a similar manner. It does not contain a prescription for the specific set-up for tomorrow but contains a treatment of all the processes, procedures, and automated software systems that are at the operator's disposal. The existence of an Operating Plan, however, does not preclude the need for creating specific action plans for specific SOL or IROL exceedances identified in the OPA. When a Reliability Coordinator performs an OPA, the analysis may reveal instances of possible SOL or IROL exceedances for pre- or post-Contingency conditions. In these instances, Reliability Coordinators are expected to ensure that there are plans in place to prevent or mitigate those SOLs or IROLs, should those operating conditions be encountered the next day. The Operating Plan may contain a description of the process by which specific prevention or mitigation plans for day-to-day SOL or IROL exceedances identified in the OPA are handled and communicated. This approach could alleviate any potential administrative burden associated with perceived requirements for continual day-to-day updating of "the Operating Plan document" for compliance purposes.~~

Extreme Cold Weather Preparedness Technical Rationale and Justification for TOP-002-5

## 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 | August 2, 2006 | Adopted by Board of Trustees | Revised |
| 2 | November 1, 2006 | Adopted by Board of Trustees | Revised |
| 2 | June 14, 2007 | Fixed typo in R11., (subject to …) | Errata |
| 2a | February 10, 2009 | Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009 | Interpretation |
| 2a | December 2, 2009 | Interpretation of R11 approved by FERC on December 2, 2009 | Same Interpretation |
| 2b | November 4, 2010 | Added Appendix 2 – Interpretation of R10 adopted by the Board of Trustees | |
| 2b | October 20, 2011 | FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011) | |
| 2.1b | March 8, 2012 | Errata adopted by Standards Committee;<br>(Removed unnecessary language from the Effective Date section. -Deleted retired sub-requirements from Requirement R14) | Errata |
| 2.1b | April 11, 2012 | Additional errata adopted by Standards Committee; (Deleted language from retired sub-requirement from Measure M7) | Errata |
| 2.1b | September 13, 2012 | FERC approved | Errata |
| 3 | May 6, 2012 | Revisions under Project 2007-03 | Revised |
| 3 | May 9, 2012 | Adopted by Board of Trustees | Revised |

| | | | |
|---|---|---|---|
| 4 | April 2014 | Revisions under Project 2014-03 | Revised |
| 4 | November 13, 2014 | Adopted by NERC Board of Trustees | Revisions under Project 2014-03 |
| 4 | November 19, 2015 | FERC approved TOP-002-4. Docket No. RM15-16-000. -Order No. 817. | |
| 5 | TBD | Revisions under Project 2021-07 | 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 Definitions:**~~
~~Changes made to the proposed definitions were made in order to respond to issues raised in NOPR paragraphs 55, 73, and 74 dealing with analysis of SOLs in all time horizons, questions on Protection Systems and Special Protection Systems in NOPR paragraph 78, and recommendations on phase angles from the SW Outage Report (recommendation 27). The intent of such changes is to ensure that Real-time Assessments contain sufficient details to result in an appropriate level of situational awareness. Some examples include: 1) analyzing phase angles which may result in the implementation of an Operating Plan to adjust generation or curtail transactions so that a Transmission facility may be returned to service, or 2) evaluating the impact of a modified Contingency resulting from the status change of a Special Protection Scheme from enabled/in-service to disabled/out-of-service.~~

~~**Rationale for R1:**~~
~~Terms deleted in Requirement R1 as they are now contained in the revised definition of Operational Planning Analysis~~

~~**Rationale for R2:**~~
~~The change to Requirement R2 is in response to NOPR paragraph 42 and in concert with proposed changes made to proposed TOP-001-4~~

~~**Rationale for R3:**~~
~~Changes in response to IERP recommendation~~

~~**Rationale for R4 and R5:**~~
~~These Requirements were added to address IERP recommendations~~

~~**Rationale for R6 and R7:**~~
~~Added in response to SW Outage Report recommendation 1~~

# Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard 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 |
| 45-day formal comment period with ballot –Phase 2 | 2/28/23 – 4/13/23 |
| 20-day comment period and additional ballot – Phase 2 | 8/24/23 – 9/12/23 |

| Anticipated Actions | Date |
|---|---|
| 8-day final ballot | 9/29/23 – 10/6/23 |
| NERC Board of Trustees (Board) adoption | October 2023 |

# A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-~~3~~4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority 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

~~**1. Effective Date:** See Implementation Plan for Project 2021-07.~~

   **4.1.4** Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   **4.1.5** UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   **4.1.6** Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

# 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~~shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

**1.2.5.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

**1.2.5.2.** Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

**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~~UVLS;

~~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~~.~~;

**1.2.5.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

**1.2.6.** Provisions to determine reliability impacts of:

**1.2.6.1.** ~~cold~~Cold weather conditions; and

**1.2.6.2.** ~~extreme~~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~~Capability and availability;

**2.2.3.2.** ~~fuel~~Fuel supply and inventory concerns;

**2.2.3.3.** ~~fuel~~Fuel switching capabilities; and

**2.2.3.4.** ~~environmental~~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 excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

~~**2.2.8.**~~**2.2.9.** Provisions for Transmission Operators to implement operator-controlled manual Load ~~shed~~shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

~~**2.2.9.**~~**2.2.10.** Provisions to determine reliability impacts of:

~~**2.2.9.1.**~~**2.2.10.1.** ~~cold~~Cold weather conditions; and

~~**2.2.9.2.**~~**2.2.10.2.** ~~extreme~~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 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 Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

**M7.** Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

**R8**. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

**8.1.** Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

**8.1.1.** Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

**8.1.2.** Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

**8.1.3.** Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

**8.1.4.** Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions; and

**8.1.5.** Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

**8.2.** Provisions to provide the Load shedding plan to the Transmission Operator for review.

**M8.** Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner

notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding 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 Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

## C. Compliance

### 1. Compliance Monitoring Process

**~~1.1.~~ Compliance Enforcement Authority**

**1.1.** **:** "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**

**1.2.** **:** 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 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:**

**1.3.** 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 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.<br>OR<br>The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it. |
| **R2** | 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 # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | 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.<br>OR<br>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** | 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 # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | | Operator within 30 calendar days. | |
| **R4** | N/A | N/A | The Transmission Operator or Balancing Authority failed to update and resubmit 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** | 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,<br>Balancing Authorities |

| R # | 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** | 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 | N/A | The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late. | The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late. | The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding.<br>OR<br>The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 60 days or more late. |

| | | | | |
|---|---|---|---|---|
| **R8** | N/A | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8. | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8. | The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8.<br>OR<br>The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8. |

## 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 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 |
| ~~2~~3 | October ~~28,~~26, 2022 | Adopted by Board of Trustees~~FERC Approved EOP-011-3 Docket Number RD23-1-000~~ | Revised under Project 2021-07 |
| 3 | February 16,~~2022~~ 2023 | FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094~~Adopted by Board of Trustees~~ | ~~Revised under Project 2021-07~~ |
| ~~3~~4 | TBD | ~~Effective Date~~ | Revised under Project 2021-07 |

# Attachment 1-EOP-011-~~3~~4 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, 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 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 | 10/20/2021 |
| SAR posted for comment | 12/9/2021 – 1/27/2022 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal or informal comment period with ballot | 9/5/2023 – 10/19/2023 |
| 45-day formal or informal comment period with additional ballot | 11/4/2023 – 12/19/2023 |
| XX-day final ballot | |
| Board adoption | |

## 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:** Facility Ratings
2. **Number:** FAC-008-6~~5~~
3. **Purpose:** To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on technically sound principles. A Facility Rating is essential for the determination of System Operating Limits.
4. **Applicability:**
   - **4.1.** Transmission Owner
   - **4.2.** Generator Owner
5. **Effective Date:** See Implementation Plan.

## B. Requirements and Measures

**R1.** Each Generator Owner shall have documentation for determining the Facility Ratings of its solely and jointly owned generator Facility(ies) up to the low side terminals of the main step up transformer if the Generator Owner does not own the main step up transformer and the high side terminals of the main step up transformer if the Generator Owner owns the main step up transformer. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**1.1.** The documentation shall contain assumptions used to rate the generator and at least one of the following:

- Design or construction information such as design criteria, ratings provided by equipment manufacturers, equipment drawings and/or specifications, engineering analyses, method(s) consistent with industry standards (e.g. ANSI and IEEE), or an established engineering practice that has been verified by testing or engineering analysis.
- Operational information such as commissioning test results, performance testing or historical performance records, any of which may be supplemented by engineering analyses.

**1.2.** The documentation shall be consistent with the principle that the Facility Ratings do not exceed the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

**M1.** Each Generator Owner shall have documentation that shows how its Facility Ratings were determined as identified in Requirement 1.

**R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of interconnection with the Transmission Owner that contains all of the following. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**2.1.** The methodology used to establish the Ratings of the equipment that comprises the Facility(ies) shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronic Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.

**2.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R2, Part 2.1 including identification of how each of the following were considered:

**2.2.1.** Equipment Rating standard(s) used in development of this methodology.

**2.2.2.** Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

**2.2.3.** Ambient conditions (for particular or average conditions or as they vary in real-time).

**2.2.4.** Operating limitations.[1]

**2.3.** A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

**2.4.** The process by which the Rating of equipment that comprises a Facility is determined.

**2.4.1.** The scope of equipment addressed shall include, but not be limited to, conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

**2.4.2.** The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

**M2.** Each Generator Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 2, Parts 2.1 through 2.4.

**R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following: *[Violation Risk Factor: Medium] [ Time Horizon: Long-term Planning]*

**3.1.** The methodology used to establish the Ratings of the equipment that comprises the Facility shall be consistent with at least one of the following:

- Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications such as nameplate rating.
- One or more industry standards developed through an open process such as Institute of Electrical and Electronics Engineers (IEEE) or International Council on Large Electric Systems (CIGRE).
- A practice that has been verified by testing, performance history or engineering analysis.



[1] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

**3.2.** The underlying assumptions, design criteria, and methods used to determine the Equipment Ratings identified in Requirement R3, Part 3.1 including identification of how each of the following were considered:

**3.2.1.** Equipment Rating standard(s) used in development of this methodology.

**3.2.2.** Ratings provided by equipment manufacturers or obtained from equipment manufacturer specifications.

**3.2.3.** Ambient conditions (for particular or average conditions or as they vary in real-time).

**3.2.4.** Operating limitations.[2]

**3.3.** A statement that a Facility Rating shall respect the most limiting applicable Equipment Rating of the individual equipment that comprises that Facility.

**3.4.** The process by which the Rating of equipment that comprises a Facility is determined.

**3.4.1.** The scope of equipment addressed shall include, but not be limited to, transmission conductors, transformers, relay protective devices, terminal equipment, and series and shunt compensation devices.

**3.4.2.** The scope of Ratings addressed shall include, as a minimum, both Normal and Emergency Ratings.

**M3.** Each Transmission Owner shall have a documented Facility Ratings methodology that includes all of the items identified in Requirement 3, Parts 3.1 through 3.4.

**R4.** Reserved.

**M4.** Reserved.

**R5.** Reserved.

**M5.** Reserved.

**R6.** Each Transmission Owner and Generator Owner shall ~~have~~ develop Facility Ratings for its solely and jointly owned BES Facilities accurately identifying the rating of the most Limiting Element(s) in accordance ~~that are consistent~~ with ~~the~~ its associated Facility Ratings methodology or documentation for determining its Facility Ratings. *[ViolationRisk Factor: Medium] [Time Horizon: Operations Planning]*

**6.1.** For a BES Facility where no entity owns the Facility in its entirety, all applicable entities that own the Facility shall coordinate development of a common Facility Rating using one or a combination of the following:

- Entities shall use the most limiting Equipment Rating of their solely owned Elements and the most limiting Equipment Rating(s) from the



[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

other Element owner(s).

- For Element(s) with multiple owners, the owners shall designate one owner to solely develop the most limiting Equipment Rating(s) for the Element(s).

**M6.** Each Transmission Owner and Generator Owner shall have evidence to show that its Facility Ratings accurately identify the rating of the most Limiting Element(s) in accordance ~~are consistent~~ with the documentation for determining its Facility Ratings as specified in Requirement R1 or consistent with its Facility Ratings methodology as specified in Requirements R2 and R3~~ (Requirement R6)~~. Where no entity owns a Facility in its entirety, each entity shall have evidence to show that its Facility Ratings were developed in accordance with Requirement R6 Part 6.1.

**R7.** Reserved.

**M7.** Reserved.



[2] Such as temporary de-ratings of impaired equipment in accordance with good utility practice.

**R8.** Each Transmission Owner (and each Generator Owner subject to Requirement R2) shall provide requested information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

**8.1.** As scheduled by the requesting entities:

**8.1.1.** Facility Ratings

**8.1.2.** Identity of the most limiting equipment of the Facilities

**8.2.** Within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a Thermal Rating that limits the use of Facilities under the requester's authority by causing any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center:

**8.2.1.** Identity of the existing next most limiting equipment of the Facility

**8.2.2.** The Thermal Rating for the next most limiting equipment identified in Requirement R8, Part 8.2.1.

**M8.** Each Transmission Owner (and Generator Owner subject to Requirement R2) shall have evidence, such as a copy of a dated electronic note, or other comparable evidence to show that it provided its Facility Ratings and identity of limiting equipment to its associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) in accordance with Requirement R8.

**R9.** Each Transmission Owner and Generator Owner shall have a process to correct each rating discrepancy found in either Element or Equipment Rating(s) used to develop Facility Ratings, that includes developing timelines to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**9.1.** Complete the corrections

**9.2.** Determine if an extent of condition review is necessary

**9.3.** Perform extent of condition review when necessary

**M9.** Each Transmission Owner and Generator Owner shall have a documented process to correct rating discrepancies found in either Element or Equipment Rating(s) that includes the items identified in Requirement R9, Parts 9.1, 9.2, and 9.3

## 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. Compliance Monitoring and Enforcement Processes:**~~

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

- ~~Compliance Violation Investigations~~
- ~~Complaints~~

~~1.3.~~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 belowis 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 to retain specific evidence for a longer period of time as part of an investigation.

- The Generator Owner shall keep its current documentation (for R1) and any modifications to the documentation that were in force since last compliance audit period for Measure M1 and Measure M6.
- The Generator Owner shall keep its current, in force Facility Ratings methodology (for R2) and any modifications to the methodology that were in force since last compliance audit period for Measure M2 and Measure M6.
- The Transmission Owner shall keep its current, in force Facility Ratings methodology (for R3) and any modifications to the methodology that were in force since the last compliance audit for Measure M3 and Measure M6.
- The Transmission Owner and Generator Owner shall keep its current, in force Facility Ratings and any changes to those ratings for three calendar years for Measure M6.
- The Transmission Owner (and Generator Owner that is subject to Requirement R2) shall keep evidence for Measure M8 for three calendar years.
- The Transmission Owner and Generator Owner shall keep its current discrepancy correction process and any modifications to the process for three calendar years for Measure M9.
- If a Generator Owner or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until found compliant.
- The Compliance Enforcement Authority shall keep the last audit and all subsequent compliance records.

~~1.4.~~1.3. **Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refersto 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 Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.1. | The Generator Owner's Facility Rating documentation did not address Requirement R1, Part 1.2. | The Generator Owner failed to provide documentation for determining its Facility Ratings. |
| **R2.** | The Generator Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R2:<br>• 2.1.<br>• 2.2.1<br>• 2.2.2<br>• 2.2.3<br>• 2.2.4 | The Generator Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R2:<br>• 2.1<br>• 2.2.1<br>• 2.2.2<br>• 2.2.3<br>• 2.2.4 | The Generator Owner's Facility Rating methodology did not address all the components of Requirement R2, Part 2.4.<br>OR<br>The Generator Owner failed to include in its Facility Rating Methodology, three of the following Parts of Requirement R2:<br>• 2.1.<br>• 2.2.1<br>• 2.2.2<br>• 2.2.3<br>• 2.2.4 | The Generator Owner's Facility Rating methodology failed to recognize a facility's rating based on the most limiting component rating as required in Requirement R2, Part 2.3<br>OR<br>The Generator Owner failed to include in its Facility Rating Methodology four or more of the following Parts of Requirement R2:<br>• 2.1<br>• 2.2.1<br>• 2.2.2<br>• 2.2.3<br>• 2.2.4 |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R3.** | The Transmission Owner failed to include in its Facility Rating methodology one of the following Parts of Requirement R3:<br>• 3.1<br>• 3.2.1<br>• 3.2.2<br>• 3.2.3<br>• 3.2.4 | The Transmission Owner failed to include in its Facility Rating methodology two of the following Parts of Requirement R3:<br>• 3.1<br>• 3.2.1<br>• 3.2.2<br>• 3.2.3<br>• 3.2.4 | The Transmission Owner's Facility Rating methodology did not address either of the following Parts of Requirement R3:<br>• 3.4.1<br>• 3.4.2<br>OR<br>The Transmission Owner failed to include in its Facility Rating methodology three of the following Parts of Requirement R3:<br>• 3.1<br>• 3.2.1<br>• 3.2.2<br>• 3.2.3<br>• 3.2.4 | The Transmission Owner's Facility Rating methodology failed to recognize a Facility's rating based on the most limiting component rating as required in Requirement R3, Part 3.3<br>OR<br>The Transmission Owner failed to include in its Facility Rating methodology four or more of the following Parts of Requirement R3:<br>• 3.1<br>• 3.2.1<br>• 3.2.2<br>• 3.2.3<br>• 3.2.4 |
| **R4.** Reserved. | | | | |
| **R5.** Reserved. | | | | |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R6.** | The responsible entity failed to develop ~~establish~~ Facility Ratings ~~consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings~~ for 5% or less of its BES Facilities in accordance with Requirement R6, Part 6.1. ~~solely owned and jointly owned Facilities. (R6)~~ | The responsible entity failed to develop ~~establish~~ Facility Ratings ~~consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings~~ for more than 5% of its BES Facilities~~or more~~, but less than up to (and including) 10% of its BES Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. ~~solely owned and jointly owned Facilities. (R6)~~ | The responsible entity failed to develop ~~establish~~ Facility Ratings ~~consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings~~ for more than 10% of its BES Facilities, but less than up to (and including) 15% of its BES ~~solely owned and jointly owned~~ Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. ~~(R6)~~ | The responsible entity failed to develop ~~establish~~ Facility Ratings ~~consistent with the associated Facility Ratings methodology or documentation for determining the Facility Ratings~~ for more than15% of its BES ~~solely owned and jointly owned~~ Facilities in accordance with Requirement R6 and Requirement R6, Part 6.1. ~~(R6)~~ |

| | | | | |
|---|---|---|---|---|
| | | | | |
| **R7.** Reserved. | | | | |
| **R8.** | The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by up to and including 15 calendar days. (R8, Part 8.1)<br>OR<br>The responsible entity provided less than 100%, | The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 15 calendar days but less than or equal to 25 calendar days. (R8, Part 8.1)<br>OR<br>The responsible entity provided less than 95%, but | The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 25 calendar days but less than or equal to 35 calendar days. (R8, Part 8.1)<br>OR<br>The responsible entity provided less than 90%, but | The responsible entity provided its Facility Ratings to all of the requesting entities but missed meeting the schedules by more than 35 calendar days. (R8, Part 8.1)<br>OR<br>The responsible entity provided less than 85% of the required Rating information to all of the |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | but not less than or equal to 95% of the required Rating information to all of the requesting entities. (R8, Part 8.1)<br>OR<br>The responsible entity provided the required Rating information to the requesting entity, but the information was provided up to and including 15 calendar days late. (R8, Part 8.2)<br>OR<br>The responsible entity provided less than 100%, but not less than or equal to 95% of the required Rating information to the requesting entity. (R8, Part 8.2) | not less than or equal to 90% of the required Rating information to all of the requesting entities. (R8, Part 8.1)<br>OR<br>The responsible entity provided the required Rating information to the requesting entity, but did so more 15 calendar days but less than or equal to 25 calendar days late. (R8, Part 8.2)<br>OR<br>The responsible entity provided less than 95%, but not less than or equal to 90% of the required Rating information to the requesting entity. (R8, Part 8.2) | not less than or equal to 85% of the required Rating information to all of the requesting entities. (R8, Part 8.1)<br>OR<br>The responsible entity provided the required Rating information to the requesting entity, but did so more than 25 calendar days but less than or equal to 35 calendar days late. (R8, Part 8.2)<br>OR<br>The responsible entity provided less than 90%, but no less than or equal to 85% of the required Rating information to the requesting entity. (R8, Part 8.2) | requesting entities. (R8, Part 8.1)<br>OR<br>The responsible entity provided the required Rating information to the requesting entity, but did so more than 35 calendar days late. (R8, Part 8.2)<br>OR<br>The responsible entity provided less than 85 % of the required Rating information to the requesting entity. (R8, Part 8.2)<br>OR<br>The responsible entity failed to provide its Rating information to the requesting entity. (R8, Part 8.1) |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| R9 | The entity failed to include one of the elements required by Parts 9.1, 9.2, and 9.3. | The entity failed to include two of the elements required by Parts 9.1, 9.2, and 9.3. | The entity failed to include all elements required by Parts 9.1, 9.2, and 9.3. | The entity failed to have a process as required by Requirement R9. |

## D. Regional Variances

None.

## E. Associated Documents

NERC Reliability Standard FAC-008-6 Implementation Plan

NERC Reliability Standard FAC-008-6 Technical Rationale.

~~None.~~

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | Feb 7, 2006 | Approved by Board of Trustees | New |
| 1 | Mar 16, 2007 | Approved by FERC | New |
| 2 | May 12, 2010 | Approved by Board of Trustees | Complete Revision, merging FAC_008-1 and FAC-009-1 under Project 2009-06 and address directives from Order 693 |
| 3 | May 24, 2011 | Addition of Requirement R8 | Project 2009-06 Expansion to address third directive from Order 693 |
| 3 | May 24, 2011 | Adopted by NERC Board of Trustees | |
| 3 | November 17, 2011 | FERC Order issued approving FAC-008-3 | |
| 3 | May 17, 2012 | FERC Order issued directing the VRF for Requirement R2 be changed from "Lower" to "Medium" | |
| 3 | February 7, 2013 | R4 and R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval. | |
| 3 | November 21, 2013 | R4 and R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02) | |
| 4 | May 9, 2020 | R7 and R8 and associated elements adopted by NERC Board of Trustees for retirement as part of Project 2018-03 Standards Efficiency Review Retirements. | |
| 4 | September 17, 2020 | Remanded by FERC (Order No. 873). | Withdrawn |
| 5 | February 4, 2021 | Adopted by NERC Board of Trustees | Requirement R8 and associated elements restored in response |

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| | | | to FERC Order No. 873. |
| 5 | April 7,2021 | FERC Order approving FAC-008-5. Docket No. RD21-4-000 | |
| 5 | October 1,2021 | Effective Date | |
| 6 | TBD | TBD | Revised under Project 2021-08 |

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# Project 2022-01 Reporting ACE Definition and Associated Terms | Draft 2 (Redline)

The drafting team (DT) is seeking comment on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. The DT is proposing acronyms to some currently approved and new Glossary terms as shown in redline. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*DT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view. The fourth column identifies the currently effective Reliability Standards or *Glossary* terms in which the proposed terms are used.

| Retired, Modified, or Newly Proposed Definitions | | | | | |
|---|---|---|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **DT Proposed New or Revised REDLINE TO Currently Approved** | **Standards Effected / Definitions Affected** | **Technical Guidelines / Reference Documents** | **Notes** |
| **Inadvertent Interchange Management – ($I_{IM}$)** | New term to NERC glossary | A term used in Reporting ACE to allow for management of Inadvertent Interchange and correction of Time Error. The $I_{IM}$ value is not used for unilateral paybacks and is null unless there is a regional procedure in place to coordinate an inadvertent control methodology for an Interconnection. | **Standards**<br>None<br><br>**Terms**<br>Reporting Ace (*proposed*) | | New term to NERC glossary |
| **Reporting Area Control Error – (Reporting ACE)** | The scan rate values of a Balancing Authority Area's (BAA) Area Control Error (ACE) measured in MW includes the difference between the | The scan rate values of a Balancing Authority Area's Area Control Error (ACE) measured in MW, which includes the error in scheduled interchange adjusted | **Standards**<br>• BAL-001-2<br>• BAL-002-3<br>• BAL-005-1 | Technical Reference Document: Balancing and Frequency | Modified to reflect a common term across all multiple BA interconnections. |

| Retired, Modified, or Newly Proposed Definitions | | | | | |
|---|---|---|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **DT Proposed New or Revised REDLINE TO Currently Approved** | **Standards Effected / Definitions Affected** | **Technical Guidelines / Reference Documents** | **Notes** |
| | Balancing Authority Area's Actual Net Interchange and its Scheduled Net Interchange, plus its Frequency Bias Setting obligation, plus correction for any known meter error. In the Western Interconnection, Reporting ACE includes Automatic Time Error Correction($_{ATEC}$).<br>Reporting ACE is calculated as follows:<br>Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$<br>Reporting ACE is calculated in the Western Interconnection as follows:<br>Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{ATEC}$<br>Where:<br>• $NI_A$ = Actual Net Interchange.<br>• $NI_S$ = Scheduled Net Interchange.<br>• B = Frequency Bias Setting.<br>• $F_A$ = Actual Frequency. | for Frequency Bias obligation, known meter error, and inadvertent management.<br>Reporting ACE is calculated as follows:<br>Reporting ACE = $(NI_A - NI_S) - 10B (F_A - F_S) - I_{ME} + I_{IM}$<br>Where:<br>• $NI_A$ = Actual Net Interchange.<br>• $NI_S$ = Scheduled Net Interchange.<br>• B = Frequency Bias Setting.<br>• $F_A$ = Actual Frequency.<br>• $F_S$ = Scheduled Frequency.<br>• $I_{ME}$ = Interchange Meter Error.<br>$I_{IM}$ = Inadvertent Interchange Management. (Term is expresssed if a regional procedure exists, otherwise is null and does not need to be included in the Balancing Authority's Reporting ACE.)<br>○ In the Western | **Terms**<br>• Automatic Generation Control;<br>• Interchange Meter Error ($I_{ME}$) *(current and proposed)*;<br>• Pre-Reporting Contingency Event ACE Value;<br>• Pseudo-Tie (*current and proposed*) | Control<br><br>Technical Reference Document: Integrating Reporting ACE with the NERC Reliability Standards<br><br>Technical Reference Document: Area Control Error Diversity Interchange Process | This change will allow regions to create methodologies to control Inadvertent Interchange accumulations.<br><br>Added ADI to the updated version. |

| Retired, Modified, or Newly Proposed Definitions | | | | | |
|---|---|---|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **DT Proposed New or Revised REDLINE TO Currently Approved** | **Standards Effected / Definitions Affected** | **Technical Guidelines / Reference Documents** | **Notes** |
| | • $F_S$ = Scheduled Frequency.<br>• $I_{ME}$ = Interchange Meter Error.<br>• $I_{IATEC}$ = Automatic Time Error Correction.<br><br>All NERC Interconnections operate using the principles of Tie-line Bias (TLB) Control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE equation that is(are) implemented for all BAAs on an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:<br>1. All portions of the Interconnection are included in exactly one BAA so that the sum of all BAAs' generation, load, and loss is | Interconnection this term is $I_{ATEC}$.<br><br>All NERC Interconnections operate using the principles of TieLine Bias (TLB) control and require the use of an ACE equation similar to the Reporting ACE defined above. Any modification(s) to this specified Reporting ACE that is(are) implemented for all BAAs in~~on~~ an Interconnection and is(are) consistent with the following four principles of Tie Line Bias control will provide a valid alternative to this Reporting ACE equation:<br>1. Each individual portion of the Interconnection is included in exactly one BAA so that the sum of all BAAs' generation, Load, and losses is the same as total Interconnection generation, Load, and losses;<br>2. The algebraic sum of all BAAs' Scheduled Net Interchange is | | | |

| Retired, Modified, or Newly Proposed Definitions | | | | | |
|---|---|---|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **DT Proposed New or Revised REDLINE TO Currently Approved** | **Standards Effected / Definitions Affected** | **Technical Guidelines / Reference Documents** | **Notes** |
| | the same as total Interconnection generation, load, and loss;<br>2. The algebraic sum of all BAAs' Scheduled Net Interchange is equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times;<br>3. The use of a common Scheduled Frequency FS for all BAAs at all times; and,<br>4. Excludes metering or computational errors. (The inclusion and use of the IME term corrects for known metering or computational errors.) | equal to zero at all times and the sum of all BAAs' Actual Net Interchange values is equal to zero at all times~~;~~ This includes effects of ACE Diversity Interchnage (ADI) implementations;<br>3. The use of a common Scheduled Frequency for all BAAs at all times; and,<br>4. Excludes metering or computational errors. (The inclusion and use of the $I_{ME}$ term corrects for known metering or computational errors.) | | | |

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# Project 2022-01 Reporting ACE Definition and Associated Terms | Draft 1

The drafting team (DT) is seeking comment on the following new or modified terms used in the proposed standards. The first column (*NERC Glossary Term*) provides the NERC Glossary term being modified or proposed as a new. The DT is proposing acronyms to some currently approved and new Glossary terms as shown in redline. The second column (*Currently Approved Definition*) provides the currently approved definition and the third column (*DT Proposed New or Revised)* reflects the proposed modifications to the current definitions in redline and also reflects newly proposed definitions in clean view. The fourth column identifies the currently effective Reliability Standards or *Glossary* terms in which the proposed terms are used.

| Retired, Modified, or Newly Proposed Definitions | | | | | |
|---|---|---|---|---|---|
| **NERC Glossary Term** | **Currently Approved Definition** | **DT Proposed New or Revised REDLINE TO Currently Approved** | **Standards Effected / Definitions Affected** | **Technical Guidelines / Reference Documents** | **Notes** |
| **ACE Diversity Interchange (ADI)** | | A frequency neutral exchange program where multiple participating Balancing Authorities utilize it to achieve reductions in their generation control and Reporting ACE through offsets to either Actual Net Interchange or Scheduled Net Interchange ACE components to create an ACE value closer to zero for each participant. | Included in Reporting ACE definition. | | New definition |

# 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 | 01/19/2022 |
| SAR posted for comment | 2/1/2022 – 3/02/2022 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal or informal comment period with ballot | 6/1/2023 – 7/17/2023 |
| 45-day formal or informal comment period with additional ballot | 9/1/2023 – 10/15/2023 |
| XX-day final ballot | |
| Board adoption | 12/12/2023 |

# 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):

Distributed Energy Resource (DER)

Generators and energy storage technologies connected to the Distribution Provider's system that are capable of providing active power in non-isolated parallel operation with the Bulk Electric System.

## A. Introduction

1. **Title: Data for Power System Modeling and Analysis**

2. **Number: MOD-032-~~1~~2**

3. **Purpose:** To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

4. **Applicability:**

   **4.1. Functional Entities:**

   **4.1.1** Balancing Authority

   **4.1.2** Generator Owner

   **4.1.3** ~~Load Serving Entity~~Distribution Provider

   **4.1.4** Planning Authority and Planning Coordinator (hereafter collectively referred to as "Planning Coordinator")

   This ~~proposed~~ standard combines "Planning Authority" with "Planning Coordinator" in the list of applicable functional entities. The NERC Functional Model lists "Planning Coordinator" while the registration criteria list "Planning Authority," and they are not yet synchronized. Until that occurs, the ~~proposed~~ standard applies to both Planning Authority and Planning Coordinator.

   **4.1.5** Resource Planner

   **4.1.6** Transmission Owner

   **4.1.7** Transmission Planner

   **4.1.8** Transmission Service Provider

5. **Effective Date: See Implementation Plan.**

   ~~MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirement R1 shall become effective on the first day of the first calendar quarter that is 12 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

   ~~MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a~~

~~standard to go into effect. Where approval by an applicable governmental authority is not required, MOD-032-21, Requirements R2, R3, and R4 shall become effective on the first day of the first calendar quarter that is 24 36 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~

~~**6. Background:**~~

~~MOD-032-1 exists in conjunction with MOD-033-1, both of which are related to system-level modeling and validation. Reliability Standard MOD-032-1 is a consolidation and replacement of existing MOD-010-0, MOD-011-0, MOD-012-0, MOD-013-1, MOD-014-0, and MOD-015-0.1, and it requires data submission by applicable data owners to their respective Transmission Planners and Planning Coordinators to support the Interconnection-wide case building process in their Interconnection. Reliability Standard MOD-033-1 is a new standard, and it requires each Planning Coordinator to implement a documented process to perform model validation within its planning area.~~

~~The transition and focus of responsibility upon the Planning Coordinator function in both standards are driven by several recommendations and FERC directives from FERC Order No. 693, which are discussed in greater detail in the rationale sections of the standards. One of the most recent and significant set of recommendations came from the NERC Planning Committee's System Analysis and Modeling Subcommittee (SAMS). SAMS proposed several improvements to the modeling data standards, to include consolidation of the standards (the SAMS whitepaper is available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here: http://www.nerc.com/comm/PC/Agendas%20Highlights%20and%20Minutes%20DL/2012/2012_Dec_PC%20Agenda.pdf).~~

## B. Requirements and Measures

**R1.** Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**1.1.** The data listed in Attachment 1.

**1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):

**1.2.1.** Data format;

**1.2.2.** Level of detail to which equipment shall be modeled;

**1.2.3.** Case types or scenarios to be modeled; and

**1.2.4.** A schedule for submission of data at least once every 13 calendar months.

**1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

**M1.** Each Planning Coordinator and Transmission Planner shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.

**R2.** Each Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**M2.** Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to its Transmission Planner(s) and Planning Coordinator(s); or written confirmation that the data has not changed.

**R3.** Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

**3.1.** Provide either updated data or an explanation with a technical basis for maintaining the current data;

**3.2.** Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.

**M3.** Each registered entity identified in Requirement R3 that has received written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to its Planning Coordinator or Transmission Planner within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying

Planning Coordinator or Transmission Planner), or a statement that it has not received written notification regarding technical concerns with the data submitted.

**R4.** Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

**M4.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the ERO or its designee.

## 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.

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

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

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

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

~~Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.~~

~~**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 Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include less than or equal to 25% of the required components specified in Requirement R1. | The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 25% but less than or equal to 50% of the required components specified in Requirement R1. | The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 50% but less than or equal to 75% of the required components specified in Requirement R1. | The Planning and Transmission Planner(s) Coordinator did not develop any steady-state, dynamics, and short circuit modeling data requirements and reporting procedures required by Requirement R1;<br>OR<br>The Planning Coordinator and Transmission Planner(s) developed steady-state, dynamics, and short circuit modeling data requirements and reporting procedures, but failed to include greater than 75% of the required |

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| | | | | | | components specified in Requirement R1. |
| **R2** | **Long-term Planning** | **Medium** | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide less than or equal to 25% of the required data specified in Attachment 1;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 25% but less than or equal to 50% of the required data specified in Attachment 1;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 50% but less than or equal to 75% of the required data specified in Attachment 1;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider did not provide any steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s);<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but less than or equal to 25% of the required data failed to meet data format, shareability, level of detail, or case type specifications;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide steady-state, dynamics, and short | Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 25% but less than or equal to 50% of the required data failed to meet data format, shareability, level of detail, or case type specifications;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to | Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 50% but less than or equal to 75% of the required data failed to meet data format, shareability, level of detail, or case type specifications;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to | steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but failed to provide greater than 75% of the required data specified in Attachment 1;<br><br>OR<br><br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider provided steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s), but greater than 75% of |

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| | | | circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in less than or equal to 15 calendar days after the specified date. | provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 15 but less than or equal to 30 calendar days after the specified date. | provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 30 but less than or equal to 45 calendar days after the specified date. | the required data failed to meet data format, shareability, level of detail, or case type specifications;<br>OR<br>The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, or Transmission Service Provider failed to provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) within the schedule specified by the data requirements and reporting procedures but did provide the data in greater than 45 calendar days after the specified date. |

| | | | | | | |
|---|---|---|---|---|---|---|
| **R3** | **Long-term Planning** | **Lower** | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within 105 calendar days (or within 15 calendar days after the longer period agreed upon by the notifying Planning | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 105 calendar days but less than or equal to 120 calendar days (or within greater than 15 | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 90 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner), but did provide the response within greater than 120 calendar days but less than or equal to 135 calendar days (or within greater than 30 | The Balancing Authority, Generator Owner, ~~Load Serving Entity~~Distribution Provider, Resource Planner, Transmission Owner, or Transmission Service Provider failed to provide a written response to its Transmission Planner(s) or Planning Coordinator(s) according to the specifications of Requirement R4 within 135 calendar days (or within a longer period agreed upon by the notifying Planning Coordinator or Transmission Planner). |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | Coordinator or Transmission Planner). | calendar days but less than or equal to 30 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner). | calendar days but less than or equal to 45 calendar days after the longer period agreed upon by the notifying Planning Coordinator or Transmission Planner). | |
| **R4** | **Long-term Planning** | **Medium** | The Planning Coordinator made available the required data to the ERO or its designee but failed to provide less than or equal to 25% of the required data in the format specified by the ERO or its designee. | The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 25% but less than or equal to 50% of the required data in the format specified by the ERO or its designee. | The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 50% but less than or equal to 75% of the required data in the format specified by the ERO or its designee. | The Planning Coordinator made available the required data to the ERO or its designee but failed to provide greater than 75% of the required data in the format specified by the ERO or its designee. |

## D. Regional Variances

None.

## ~~E. Interpretations~~

~~None.~~

## ~~F.~~E. Associated Documents

NERC Reliability Standard MOD-032-2 Implementation Plan

NERC Reliability Standard MOD-032-2 Technical Rationale

~~None.~~

## ~~Guidelines and Technical Basis~~

~~For purposes of jointly developing steady-state, dynamics, and short circuit modeling data requirements and reporting procedures under Requirement R1, if a Transmission Planner (TP) and Planning Coordinator (PC) mutually agree, a TP may collect and aggregate some or all data from providing entities, and the TP may then provide that data directly to the PC(s) on behalf of the providing entities. The submitting entities are responsible for getting the data to both the TP and the PC, but nothing precludes them from arriving at mutual agreements for them to provide it to the TP, who then provides it to the PC. Such agreement does not relieve the submitting entity from responsibility under the standard, nor does it make the consolidating entity liable for the submitting entities' compliance under the standard (in essence, nothing precludes parties from agreeing to consolidate or act as a conduit to pass the data, and it is in fact encouraged in certain circumstances, but the requirement is aimed at the act of submitting the data). Notably, there is no requirement for the TP to provide data to the PC. The intent, in part, is to address potential concerns from entities that they would otherwise be responsible for the quality, nature, and sufficiency of the data provided by other entities.~~

~~The requirement in Part 1.3 to include specifications for distribution or posting of the data requirements and reporting procedures could be accomplished in many ways, to include posting on a Web site, distributing directly, or through other methods that the Planning Coordinator and each of its Transmission Planners develop.~~

~~An entity submitting data per the requirements of this standard who needs to determine the PC for the area, as a starting point, should contact the local Transmission Owner (TO) for information on the TO's PC. Typically, the PC will be the same for both the local TO and those entities connected to the TO's system. If this is not the case, the local TO's PC can typically provide contact information on other PCs in the area. If the entity (e.g., a Generator Owner [GO]) is requesting connection of a new generator, the entity can determine who the PC is for that area at the time a generator connection request is submitted. Often the TO and PC are the same entity, or the TO can provide information on contacting the PC. The entity should specify as the reason for the request to the TO that the entity needs to provide data to the PC according to this standard. Nothing in the proposed requirement language of this standard is intended to preclude coordination between entities such that one entity, serving only as a conduit, provides the other entity's data to the PC. This can be accomplished if it is mutually agreeable by, for example, the GO (or other entity), TP, and the PC. This does not, however, relieve the original entity from its obligations under the standard to provide data, nor does it pass on the compliance obligation of the entity. The original entity is still accountable for making sure that the data has been provided to the PC according to the requirements of this standard.~~

~~The standard language recognizes that differences exist among the Interconnections. Presently, the Eastern/Quebec and Texas Interconnections build seasonal cases on an annual basis, while the Western Interconnection builds cases on a continuous basis throughout the year. The intent of the standard is not to change established processes and procedures in each of the Interconnections, but to create a framework to support both what is already in place or~~

what it may transition into in the future, and to provide further guidance in a common platform for the collection of data that is necessary for the building of the Interconnection-wide case(s).

The construct that these standards replace did not specifically list which Functional Entities were required to provide specific data. Attachment 1 specifically identifies the entities responsible for the data required for the building of the Interconnection-wide case(s).

**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 consolidates the concepts from the original data requirements from MOD-011-0, Requirement R1, and MOD-013-0, Requirement R1. The original requirements specified types of steady-state and dynamics data necessary to model and analyze the steady-state conditions and dynamic behavior or response within each Interconnection. The original requirements, however, did not account for the collection of short circuit data also required to perform short circuit studies. The addition of short circuit data also addresses the outstanding directive from FERC Order No. 890, paragraph 290.

In developing a performance-based standard that would address the data requirements and reporting procedures for model data, it was prohibitively difficult to account for all of the detailed technical concerns associated with the preparation and submittal of model data given that many of these concerns are dependent upon evolving industry modeling needs and software vendor terminology and product capabilities.

This requirement establishes the Planning Coordinator jointly with its Transmission Planners as the developers of technical model data requirements and reporting procedures to be followed by the data owners in the Planning Coordinator's planning area. FERC Order No. 693, paragraphs 1155 and 1162, also direct that the standard apply to Planning Coordinators. The inclusion of Transmission Planners in the applicability section is intended to ensure that the Transmission Planners are able to participate jointly in the development of the data requirements and reporting procedures.

This requirement is also consistent with the recommendations from the NERC System Analysis and Modeling Subcommittee (SAMS) White Paper titled "Proposed Improvements for NERC MOD Standards", available from the December 2012 NERC Planning Committee's agenda package, item 3.4, beginning on page 99, here:

Aside from recommendations in support of strengthening and improving MOD-010 through MOD-015, the SAMS paper included the following suggested improvements:

reduce the quantity of MOD standards;

~~add short circuit data as a requirement to the MOD standards; and~~

~~supply data and models:~~

~~add requirement identifying who provides and who receives data;~~

~~identify acceptability;~~

~~standard format;~~

~~how to deal with new technologies (user written models if no standard model exists); and~~

a. ~~shareability.~~
b. ~~These suggested improvements are addressed by combining the existing standards into two new standards, one standard for the submission and collection of data, and one for the validation of the planning models. Adding the requirement for the submittal of short circuit data is also an improvement from the existing standards, consistent with FERC Order No. 890, paragraph 290. In supplying data, the approach clearly identifies what data is required and which Functional Entity is required to provide the data.~~
c. ~~The requirement uses an attachment approach to support data collection. The attachment specifically lists the entities that are required to provide each type of data and the steady-state, dynamics, and short circuit data that is required.~~
d. ~~Finally, the decision to combine steady-state, dynamics, and short circuit data requirements into one requirement rather than three reflects that they all support the requirement of submission of data in general.~~
e. ~~**Rationale for R2:**~~
f. ~~This requirement satisfies the directive from FERC Order No. 693, paragraph 1155, which directs that "the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data."~~
g. ~~**Rationale for R3:**~~
h. ~~In order to maintain a certain level of accuracy in the representation of a power system, the data that is submitted must be correct, periodically checked, and updated. Data used to perform steady-state, dynamics, and short circuit studies can change, for example, as a result of new planned transmission construction (in comparison to as-built information) or changes performed during the restoration of the transmission network due to weather-related events. One set of data that changes on a more frequent basis is load data, and updates to load data are needed when new improved forecasts are created.~~
i. ~~This requirement provides a mechanism for the Planning Coordinator and Transmission Planner (that does not exist in the current standards) to collect corrected data from the entities that have the data. It provides a feedback loop to address technical concerns related to the data when the Planning Coordinator or Transmission Planner identifies technical concerns, such as concerns about~~

~~the usability of data or simply that the data is not in the correct format and cannot be used. The requirement also establishes a time-frame for response to address timeliness.~~

~~**Rationale for R4:**~~

~~This requirement will replace MOD-014 and MOD-015.~~

~~This requirement recognizes the differences among Interconnections in model building processes, and it creates an obligation for Planning Coordinators to make available data for its planning area.~~

~~The requirement creates a clear expectation that Planning Coordinators will make available data that they collect under Requirement R2 in support of their respective Interconnection-wide case(s). While different entities in each Interconnection create the Interconnection-wide case(s), the requirement to submit the data to the "ERO or its designee" supports a framework whereby NERC, in collaboration and agreement with those other organizations, can designate the appropriate organizations in each Interconnection to build the specific Interconnection-wide case(s). It does not prescribe a specific group or process to build the larger Interconnection-wide case(s), but only requires the Planning Coordinators to make available data in support of their creation, consistent with the SAMS Proposed Improvements to NERC MOD Standards (at page 3) that, "industry best practices and existing processes should be considered in the development of requirements, *as many entities are successfully coordinating their efforts."* (Emphasis added).~~

~~This requirement is about the Planning Coordinator's obligation to make information available for use in the Interconnection-wide case(s); it is not a requirement to build the Interconnection-wide case(s).~~

~~For example, under current practice, the Eastern Interconnection Reliability Assessment Group (ERAG) builds the Eastern Interconnection and Quebec Interconnection-wide cases, the Western Electricity Coordinating Council (WECC) builds the Western Interconnection-wide cases, and the Electric Reliability Council of Texas (ERCOT) builds the Texas Interconnection-wide cases. This requirement does not require a change to that construct, and, assuming continued agreement by those organizations, ERAG, WECC, and ERCOT could be the "designee" for each Interconnection contemplated by this requirement. Similarly, the requirement does not prohibit transition, and the requirement remains for the Planning Coordinators to make available the information to the ERO or to whomever the ERO has coordinated with and designated as the recipient of such information for purposes of creation of each of the Interconnection–wide cases.~~

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 1 | February 6, 2014 | Adopted by the NERC Board of Trustees. | Developed to consolidate and replace MOD-010-0, MOD -011-0, MOD-012-0, |

| | | | |
|---|---|---|---|
| | | | MOD-013-1, MOD-014-0, and MOD-015-0.1 |
| 1 | May 1, 2014 | FERC Order issued approving MOD-032-1. | See Implementation Plan posted on the Reliability Standards web page for details on enforcement dates for Requirements. |
| 2 | TBD | TBD | Revised under Project 2022-02 |
| | | | |

## MOD-032-~~01~~ 2 – ATTACHMENT 1:

### Data Reporting Requirements

*The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity[1] responsible for reporting the respective data in the table is identified by brackets "[functional entity]" adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.*

| **steady-state**<br>*(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)* | **dynamics**<br>*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)* | **short circuit** |
|---|---|---|
| 1. Each bus [TO]<br>a. nominal voltage<br>b. area, zone and owner<br>2. Aggregate Demand[2] [~~LSE~~DP, TO (when a Demand is not associated with a registered DP)]<br>a. real and reactive power*<br>b. in-service status*<br>3. Generating Units[3] [GO, RP (for future planned resources only)]<br>a. real power capabilities - gross maximum and minimum values | 1. Generator [GO, RP (for future planned resources only)]<br>2. Excitation System [GO, RP (for future planned resources only)]<br>3. Governor [GO, RP (for future planned resources only)]<br>4. Power System Stabilizer [GO, RP (for future planned resources only)]<br>5. Demand [~~LSE~~DP, TO (when a Demand is not associated with a registered DP)]<br>6. Wind Turbine Data [GO] | 1. Provide for all applicable elements in column "steady-state" [GO, RP, TO]<br>a. Positive Sequence Data<br>b. Negative Sequence Data |

[1] For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), ~~Load Serving Entity~~Distribution Provider (~~LSE~~DP), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

[2] For purposes of this item, aggregate Demand is the gross Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus rather than the net Demand that incorporates offsets due to output from Distributed Energy Resources. A ~~Load Serving Entity~~Distribution Provider is responsible for providing this information, generally through coordination with the Transmission Owner.

[3] Including synchronous condensers and pumped storage.

| **steady-state**<br>*(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)* | **dynamics**<br>*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)* | **short circuit** |
|---|---|---|
| b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above<br>c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).<br>d. regulated bus* and voltage set point* (as typically provided by the TOP)<br>e. machine MVA base<br>f. generator step up transformer data (provide same data as that required for transformer under item 6, below)<br>g. generator type (hydro, wind, fossil, solar, nuclear, etc)<br>h. in-service status*<br>4. AC Transmission Line or Circuit [TO]<br>a. impedance parameters (positive sequence)<br>b. susceptance (line charging)<br>c. ratings (normal and emergency)*<br>d. in-service status*<br>5. DC Transmission systems [TO]<br>6. Transformer (voltage and phase-shifting) [TO]<br>a. nominal voltages of windings<br>b. impedance(s)<br>c. tap ratios (voltage or phase angle)*<br>d. minimum and maximum tap position limits<br>e. number of tap positions (for both the ULTC and NLTC)<br>f. regulated bus (for voltage regulating transformers)*<br>g. ratings (normal and emergency)*<br>h. in-service status*<br>7. Reactive compensation (shunt capacitors and reactors) [TO]<br>a. admittances (MVars) of each capacitor and reactor<br>b. regulated voltage band limits* (if mode of operation not fixed)<br>c. mode of operation (fixed, discrete, continuous, etc.)<br>d. regulated bus* (if mode of operation not fixed)<br>e. in-service status*<br>8. Static Var Systems [TO]<br>a. reactive limits<br>b. voltage set point* | 7. Photovoltaic systems [GO]<br>8. Static Var Systems and FACTS [GO, TO, ~~LSE~~DP]<br>9. DC system models [TO]<br>10. Distributed Energy Resource (DER) data [DP, TO (when DER is not associated with a registered DP)]<br>~~10.~~11. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP] | c. Zero Sequence Data<br>2. Mutual Line Impedance Data~~-~~ [TO]<br>3. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP] |

| **steady-state**<br>*(Items marked with an asterisk indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)* | **dynamics**<br>*(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, and a list of all state variables)* | **short circuit** |
|---|---|---|
| c. fixed/switched shunt, if applicable<br>d. in-service status*<br>9. Distributed Energy Resource (DER) data[4] [DP, TO (when DER is not associated with a registered DP)]<br>a. Location (bus from item 1) and if DER feeder is subject to UFLS and/or UVLS<br>b. Real power capability (minimum and maximum)<br>c. Reactive power capability (minimum and maximum)<br>d. Generator type (solar, battery, etc.)<br>e. In-service date or other information to be used to make assumptions about DER capabilities related to ride-through, voltage control and/or frequency control.<br>~~9.~~10. Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling purposes. [BA, GO, ~~LSE~~DP, TO, TSP] | | |

[4]The TP/PC modeling data requirements and reporting procedures may require either aggregated or unaggregated data as necessary for local practices and the TP/PC may need to coordinate with the DP/TO to determine appropriate assumptions for equivalent distribution system impedance.

# 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 | January 25, 2023 |
| SAR posted for comment | February 7 – March 8, 2023 |

| Anticipated Actions | Date |
|---|---|
| 45-day formal or informal comment period with ballot | July to September 2023 |
| 45-day formal or informal comment period with additional ballot | December 2023 to January 2024 |
| 45-day final ballot | February 2024 |
| Board adoption | May 2024 |

# 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:** Event Reporting

2. **Number:** EOP-~~004-4~~004-5

3. **Purpose:** To improve the reliability of the Bulk Electric System (BES) by requiring the reporting of events by Responsible Entities.

4. **Applicability:**

   **4.1. Functional Entities:** For the purpose of the Requirements and the EOP-004 Attachment 1 contained herein, the following Functional Entities will be collectively referred to as "Responsible Entity."

   **4.1.1.** Reliability Coordinator

   **4.1.2.** Balancing Authority

   **4.1.3.** Transmission Owner

   **4.1.4.** Transmission Operator

   **4.1.5.** Generator Owner

   **4.1.6.** Generator Operator

   **4.1.7.** Distribution Provider

5. **Effective Date:** See the Implementation Plan for EOP-~~004-4~~004-5.

# B. Requirements and Measures

**R1.** Each Responsible Entity shall have an event reporting Operating Plan in accordance with EOP-~~004-4~~004-5 Attachment 1 that includes the protocol(s) for reporting to the Electric Reliability Organization and other organizations (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or governmental authority). *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

**M1.** Each Responsible Entity will have a dated event reporting Operating Plan that includes protocol(s) and each organization identified to receive an event report for event types specified in EOP-~~004-4~~004-5 Attachment 1 and in accordance with the entity responsible for reporting.

**R2.** Each Responsible Entity shall report events specified in EOP-~~004-4~~004-5 Attachment 1 to the entities specified per their event reporting Operating Plan by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day). *[Violation Risk Factor: Medium] [Time Horizon: Operations*

*Assessment]*

**M2.** Each Responsible Entity will have as evidence of reporting an event to the entities specified per their event reporting Operating Plan either a copy of the completed EOP-~~004-4~~**004-5** Attachment 2 form or a ~~DOE-OE~~**DOE**-417 form; and some evidence of submittal (e.g., operator log or other operating documentation, voice recording, electronic mail message, or confirmation of facsimile) demonstrating that the event report was submitted by the later of 24 hours of recognition of meeting an event type threshold for reporting or by the end of the Responsible Entity's next business day (4 p.m. local time will be considered the end of the business day).

## C. Compliance

### 1. Compliance Monitoring Process

#### 1.1. Compliance Enforcement Authority:

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

#### 1.2. Evidence Retention:

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

The following evidence retention ~~**periods**~~**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**~~**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 Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for Requirement R1, and Measure M1.
- Each Responsible Entity shall retain evidence of compliance since the last audit for Requirement R2 and Measure M2.

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

~~The Compliance Enforcement Authority shall keep the last audit records and all~~

~~requested and submitted subsequent audit records.~~

### 1.3. Compliance Monitoring and Enforcement Program

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

## Violation Severity Levels

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| **R1.** | The Responsible Entity had an event reporting Operating Plan, but failed to include one applicable event type. | The Responsible Entity had an event reporting Operating Plan, but failed to include two applicable event types. | The Responsible Entity had an event reporting Operating Plan, but failed to include three applicable event types. | The Responsible Entity had an event reporting Operating Plan, but failed to include four or more applicable event types.<br>OR<br>The Responsible Entity failed to have an event reporting Operating Plan. |
| **R2.** | The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients up to 24 hours after the timing requirement for submittal.<br>OR<br>The Responsible Entity failed to submit an event report (e.g., written or verbal) to one entity identified in its event reporting Operating Plan within 24 hours or by the end of the next business day, as applicable. | The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 24 hours but less than or equal to 48 hours after the timing requirement for submittal.<br>OR<br>The Responsible Entity failed to submit an event report (e.g., written or verbal) to two entities identified in its event reporting Operating Plan within 24 hours or by | The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 48 hours but less than or equal to 72 hours after the timing requirement for submittal.<br>OR<br>The Responsible Entity failed to submit an event report (e.g., written or verbal) to three entities identified in its event reporting Operating Plan within 24 hours or by | The Responsible Entity submitted an event report (e.g., written or verbal) to all required recipients more than 72 hours after the timing requirement for submittal.<br>OR<br>The Responsible Entity failed to submit an event report (e.g., written or verbal) to four or more entities identified in its event reporting Operating Plan within 24 hours or by the |

| R # | Violation Severity Levels | | | |
|---|---|---|---|---|
| | Lower VSL | Moderate VSL | High VSL | Severe VSL |
| | | the end of the next business day, as applicable. | the end of the next business day, as applicable. | end of the next business day, as applicable.<br>OR<br>The Responsible Entity failed to submit a report for an event in EOP-004-4 Attachment 1. |

## D. Regional Variances

None.

## E. Associated Documents

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

# EOP-004 - Attachment 1: Reportable Events

NOTE: Under certain adverse conditions (e.g. severe weather, multiple events) it may not be possible to report the damage caused by an event and issue a written event report within the timing in the standard. In such cases, the affected Responsible Entity shall notify parties per Requirement R2 and provide as much information as is available at the time of the notification. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or Voice: 404-446-9780, select Option 1.

**Submit EOP-004 Attachment 2 (or ~~DOE-OE~~DOE-417 form) pursuant to Requirements R1 and R2.**

~~**Rationale for Attachment 1:**~~

~~System-wide voltage reduction to maintain the continuity of the BES: The TOP is operating the system and is the only entity that would implement system-wide voltage reduction.~~

~~Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at a BES control center: To align EOP-004-4 with COM-001-2.1. COM-001-2.1 defined Interpersonal Communication for the NERC Glossary of Terms as: "Any medium that allows two or more individuals to interact, consult, or exchange information." The NERC Glossary of Terms defines Alternative Interpersonal Communication as: "Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to-day operation."~~

~~Complete loss of monitoring or control capability at a BES control center: Language revisions to: "Complete loss of monitoring or control capability at a BES control center for 30 continuous minutes or more" provides clarity to the "Threshold for Reporting" and better aligns with the ERO Event Analysis Process.~~

| Event Type | Entity with Reporting Responsibility | Threshold for Reporting |
|---|---|---|
| Damage or destruction of a Facility | RC, BA, TOP | Damage or destruction of a Facility within its Reliability Coordinator Area, Balancing Authority Area or Transmission Operator Area that results in action(s) to avoid a BES Emergency. |

| Event Type | Entity with Reporting Responsibility | Threshold for Reporting |
|---|---|---|
| Damage or destruction of its Facility | TO, TOP, GO, GOP, DP | Damage or destruction of its Facility that results from actual or suspected intentional human action.<br>It is not necessary to report theft unless it degrades normal operation of its Facility. |
| Physical threats to its Facility | TO, TOP, GO, GOP, DP | Physical threat to its Facility excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the Facility.<br>OR<br>Suspicious device or activity at its Facility. |
| Physical threats to its BES control center | RC, BA, TOP | Physical threat to its BES control center, excluding weather or natural disaster related threats, which has the potential to degrade the normal operation of the control center.<br>OR<br>Suspicious device or activity at its BES control center. |
| Public appeal for load reduction resulting from a BES Emergency | BA | Public appeal for load reduction to maintain continuity of the BES. |
| System-wide voltage reduction resulting from a BES Emergency | TOP | System-wide voltage reduction of 3% or more. |
| Firm load ~~sheddingresulting~~**shedding resulting** from a BES Emergency | Initiating RC, BA, or TOP | Firm load shedding ≥ 100 MW (manual or automatic). |

| Event Type | Entity with Reporting Responsibility | Threshold for Reporting |
|---|---|---|
| BES Emergency resulting in voltage deviation on a Facility | TOP | A voltage deviation of =/> 10% of nominal voltage sustained for ≥ 15 continuous minutes. |
| Uncontrolled loss of firm load resulting from a BES Emergency | BA, TOP, DP | Uncontrolled loss of firm load for ≥ 15 minutes from a single incident:<br>≥ 300 MW for entities with previous year's peak demand ≥ 3,000 MW<br>OR<br>≥ 200 MW for all other entities |
| System separation (islanding) | RC, BA, TOP | Each separation resulting in an island ≥ 100 MW |
| Generation loss | BA | Total generation loss, within one minute, of:<br>≥ 2,000 MW in the Eastern, Western, or Quebec Interconnection<br>OR<br>≥ 1,400 MW in the ERCOT Interconnection<br>Generation loss will be used to report Forced Outages not weather patterns or fuel supply unavailability for dispersed power producing resources. |
| **IBR generation loss** | **BA** | **Total aggregated generation loss of ≥ 500 MW from inverter-based resource(s) (IBR)[1] occurring within a 30 second** |

[1] For the purposes of EOP-004-5, an IBR is a generation resource consisting of one or more IBR unit(s) that connect to the transmission or subtransmission system via a single point of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units

| Event Type | Entity with Reporting Responsibility | Threshold for Reporting |
|---|---|---|
| | | period.<br><br>IBR generation loss shall be calculated using Telemetering data[2] by subtracting the lowest aggregated IBR generation output observed during a 30 second period from the pre-disturbance aggregated IBR generation output. |
| Loss of DC Tie Line | BA | Loss of a DC Tie Line, between two separate asynchronous systems, loaded at ≥ 500 MW. |

of connection. An IBR unit is a primary energy source containing an individual inverter device, individual converter device, or a grouping of multiple inverters/converters. IBR units include solar photovoltaic, Type 3 and Type 4 wind, battery energy storage, high voltage direct current (HVDC) transmission, and dynamic reactive devices such as static synchronous compensators (STATCOMs) and static VAR compensators (SVCs).

[2] Indicated IBR generation loss due to a failure of SCADA or Telemetering data is not reportable under this requirement.

| Event Type | Entity with Reporting Responsibility | Threshold for Reporting |
|---|---|---|
| Complete loss of off-site power to a nuclear generating plant (grid supply) | TO, TOP | Complete loss of off-site power (LOOP) affecting a nuclear generating station per the Nuclear Plant Interface Requirements |
| Transmission loss | TOP | Unexpected loss within its area, contrary to design, of three or more BES Facilities caused by a common disturbance (excluding successful automatic reclosing). |
| Unplanned evacuation of its BES control center | RC, BA, TOP | Unplanned evacuation from its BES control center facility for 30 continuous minutes or more. |
| Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center | RC, BA, TOP | Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability affecting its staffed BES control center for 30 continuous minutes or more. |
| Complete loss of monitoring or control capability at its staffed BES control center | RC, BA, TOP | Complete loss of monitoring or control capability at its staffed BES control center for 30 continuous minutes or more. |

# EOP-004 - Attachment 2: Event Reporting Form

| EOP-004 Attachment 2: Event Reporting Form | | |
|---|---|---|
| **Use this form to report events. The Electric Reliability Organization will accept the DOE-~~OE~~-417 form in lieu of this form, if the entity is required to submit ~~an OE~~a DOE-417 report. Submit reports to the ERO via one of the following: e-mail: systemawareness@nerc.net, Facsimile 404-446-9770 or voice: 404-446- 9780, Option 1. Also submit to other applicable organizations per Requirement R1 "… (e.g., the Regional Entity, company personnel, the Responsible Entity's Reliability Coordinator, law enforcement, or Applicable Governmental Authority)."** | | |
| **Task** | | **Comments** |
| 1. | Entity filing the report include:<br>Company name:<br>Name of contact person:<br>Email address of contact person:<br>Telephone Number:<br>Submitted by (name): | |
| 2. | Date and Time of recognized event.<br>Date: (mm/dd/yyyy)<br>Time: (hh:mm)<br>Time/Zone: | |
| 3. | Did the event originate in your system? | Yes ☐ No ☐ Unknown ☐ |
| 4. | **Event Identification and Description:** | |
| | (Check applicable box)<br>☐ Damage or destruction of a Facility<br>☐ Physical threat to its Facility<br>☐ Physical threat to its BES control center<br>☐ BES Emergency:<br>☐ firm load shedding<br>☐ public appeal for load reduction<br>☐ System-wide voltage reduction<br>☐ voltage deviation on a Facility<br>☐ uncontrolled loss of firm load<br>☐ System separation (islanding)<br>☐ Generation loss<br>☐ **IBR generation loss**<br>☐ **Loss of DC Tie Line**<br>☐ Complete loss of off-site power to a nuclear generating plant (grid supply)<br>☐ Transmission loss<br>☐ Unplanned evacuation of its BES control center<br>☐ Complete loss of Interpersonal Communication and Alternative Interpersonal Communication capability at its staffed BES control center<br>☐ Complete loss of monitoring or control capability at its staffed BES control center | Written description (optional): |

## Version History

| Version | Date | Action | Change Tracking |
|---|---|---|---|
| 2 | | Merged CIP-001-2a Sabotage Reporting and EOP-004-1 Disturbance Reporting into EOP-004-2 Event Reporting; Retire CIP-001-2a Sabotage Reporting and Retired EOP-004-1 Disturbance Reporting. | Revision to entire standard (Project 2009-01) |
| 2 | November 7, 2012 | Adopted by the NERC Board of Trustees | |
| 2 | June 20, 2013 | FERC approved | |
| 3 | November 13, 2014 | Adopted by the NERC Board of Trustees | Replaced references to Special protection System and SPS with Remedial Action Scheme and RAS |
| 3 | November 19, 2015 | FERC Order issued approving EOP-004-3. Docket No. RM15-13-000. | |
| 4 | February 9, 2017 | Adopted by the NERC Board of Trustees | Revised |
| 4 | January 18, 2018 | FERC order issued approving EOP-004-4. Docket No. RM17-12-000 | |
| **5** | **TBD** | **Adopted by the NERC Board of Trustees** | |

# ~~Guideline and Technical Basis~~

**~~Multiple Reports for a Single Organization~~**

~~For entities that have multiple registrations, the requirement is that these entities will only have to submit one report for any individual event. For example, if an entity is registered as a Reliability Coordinator, Balancing Authority and Transmission Operator, the entity would only submit one report for a particular event rather submitting three reports as each individual registered entity.~~

**~~Law Enforcement Reporting~~**

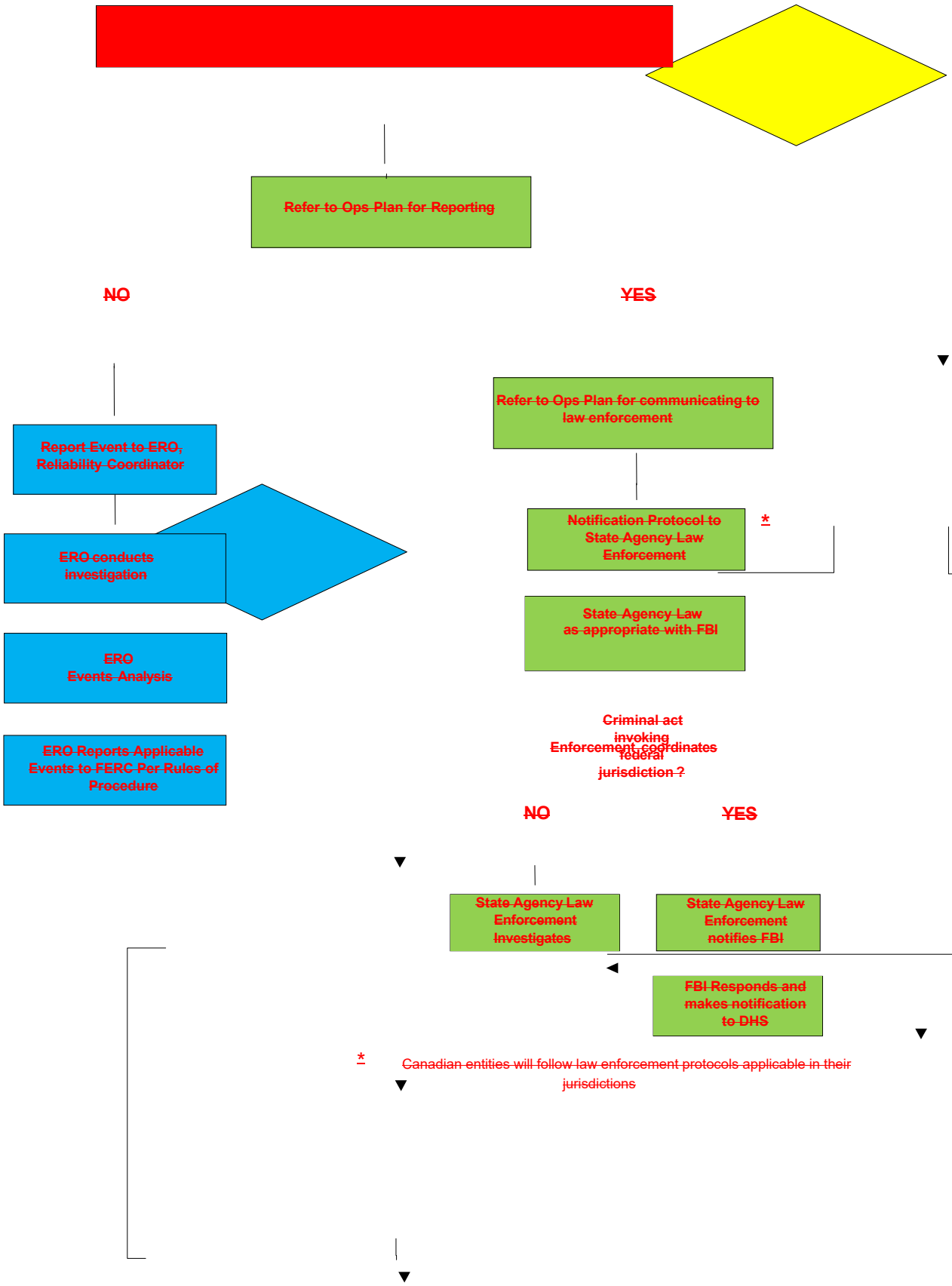
~~The reliability objective of EOP-004-4 is to improve the reliability of the Bulk Electric System by requiring the reporting of events by Responsible Entities. Certain outages, such as those due to vandalism and terrorism, may not be reasonably preventable. These are the types of events that should be reported to law enforcement. Entities rely upon law enforcement agencies to respond to and investigate those events which have the potential to impact a wider area of the BES. The inclusion of reporting to law enforcement enables and supports reliability principles such as protection of Bulk Electric System from malicious physical attack. The importance of BES awareness of the threat around them is essential to the effective operation and planning to mitigate the potential risk to the BES.~~

**~~Stakeholders in the Reporting Process~~**

- ~~Industry~~
- ~~NERC (ERO), Regional Entity~~
- ~~FERC~~
- ~~DOE~~
- ~~NRC~~
- ~~DHS – Federal~~
- ~~Homeland Security- State~~
- ~~State Regulators~~
- ~~Local Law Enforcement~~
- ~~State or Provincial Law Enforcement~~
- ~~FBI~~
- ~~Royal Canadian Mounted Police (RCMP)~~

~~The above stakeholders have an interest in the timely notification, communication and response to an incident at a Facility. The stakeholders have various levels of accountability and have a vested interest in the protection and response to ensure the reliability of the BES.~~

## Example of Reporting Process including Law Enforcement



## Supplemental Material

### Potential Uses of Reportable Information

General situational awareness, correlation of data, trend identification, and identification of potential events of interest for further analysis in the ERO Event Analysis Process are a few potential uses for the information reported under this standard. The standard requires Functional Entities to report the incidents and provide information known at the time of the report. Further data gathering necessary for analysis is provided for under the ERO Event Analysis Program and the NERC Rules of Procedure. The NERC Rules of Procedure (section 800) provide an overview of the responsibilities of the ERO in regards to analysis and dissemination of information for reliability. Jurisdictional agencies (which may include DHS, FBI, NERC, RE, FERC, Provincial Regulators, and DOE) have other duties and responsibilities.

**List to Ballot Results**
**http://standards.nerc.net/Ballots.aspx**
**(clicking in the column to the right of "Ballot Period" opens links to the Ballot Results)**

| Line | Project | Ballot Type | Start Date | End Date (Actual Ballot Ends in Parenthesis) | Ballot Results | Recommendation / Date | Have NERC Voted | Comments |
|---|---|---|---|---|---|---|---|---|
| 1 | Project 2007-24 | Initial Ballot | 6/25/2008 | 7/7/2008 | Quorum 92.21% Approval 75.84% | | | |
| 2 | Project 2007-26 | Initial Ballot | 6/25/2008 | 7/7/2008 | Quorum 89.81% Approval 75.88% | | | |
| 3 | Project 2008-04 | Initial Ballot | 6/25/2008 | 6/25/2008 | Quorum 92.21% Approval 81.63% | | | |
| 4 | Project 2008-07 | Initial Ballot | 6/25/2008 | 6/25/2008 | Quorum 89.67% Approval 81.63% | | | |
| 5 | Project 2008-09 | Recirculation Ballot | 8/13/2008 | 8/22/2008 | Quorum 89.86% Approval 90.21% | | | |
| 6 | Project 2008-09 | Initial Ballot | 6/25/2008 | 7/2/2008 | Quorum 92.21% Approval 81.37% | | | |
| 7 | Project 2007-24 | Recirculation Ballot | 8/27/2008 | 9/5/2008 | Quorum 89.67% Approval 75.84% | | | |
| 8 | Project 2007-26 | Recirculation Ballot | 8/27/2008 | 9/5/2008 | Quorum 89.86% Approval 78.95% | | | |
| 9 | Pre 2006 | RSG Standard - RS-010-A | 7/01/2008 | 7/30/2008 | Quorum 92.71% Approval 85.71% | | | |
| 10 | Pre 2006 | RSG Standard - RS-009-A | 7/01/2008 | 7/30/2008 | Quorum 92.83% Approval 89.81% | | | |
| 11 | Pre 2006 | RSG Standard - RS-008-A | 7/01/2008 | 7/30/2008 | Quorum 92.67% Approval 92.67% | | | |
| 12 | Project 2006-07 | IOC at a Standard - IROL-010-1 | 7/01/2008 | 7/30/2008 | Quorum 92.67% Approval 98.06% | | | |
| 13 | Project 2006-07 | IOC at a Standard - IROL-010-0 | 7/01/2008 | 7/30/2008 | Quorum 92.67% Approval 92.62% | | | |
| 14 | Project 2006-07 | IOC at a Standard - IROL-010-0 | 7/01/2008 | 7/30/2008 | Quorum 94.64% Approval 94.64% | | | |
| 15 | Project 2006-07 | IOC at a Standard - IROL-008-0 | 7/01/2008 | 7/30/2008 | Quorum 92.67% Approval 88.64% | | | |
| 16 | Project 2006-07 | IOC at a Standard - IROL-001-1 | 7/01/2008 | 7/30/2008 | Quorum 92.67% Approval 75.87% | | | |
| 17 | Project 2008-10 | Request for Interpretation - CIP-006-1 - Progress Energy - 0 | Initial Ballot | 8/7/2008 | Quorum 88.28% Approval 88.28% | | | |
| 18 | Pre 2006 | RSG Standard - BR-008-0 | Recirculation Ballot | 8/11/2008 | Quorum 93.51% Approval 88.49% | | | |
| 19 | Pre 2006 | RSG Standard - BR-009-0 | Recirculation Ballot | 8/11/2008 | Quorum 93.68% Approval 92.11% | | | |
| 20 | Pre 2006 | RSG Standard - BR-010-0 | Recirculation Ballot | 8/11/2008 | Quorum 93.51% Approval 85.95% | | | |
| 21 | Project 2006-07 | IOC at a Standard - IROL-001-1a | Recirculation Ballot | 8/11/2008 | Quorum 94.87% Approval 94.87% | | | |
| 22 | Project 2006-07 | IOC at a Standard - IROL-008-1 | Recirculation Ballot | 8/11/2008 | Quorum 93.21% Approval 91.49% | | | |
| 23 | Project 2006-07 | IOC at a Standard - IROL-010-1 | Recirculation Ballot | 8/11/2008 | Quorum 93.21% Approval 93.53% | | | |
| 24 | Project 2006-07 | IOC at a Standard - IROL-010-1a | Recirculation Ballot | 8/11/2008 | Quorum 95.66% Approval 95.66% | | | |
| 25 | Project 2006-07 | IOC at a Standard - IROL-010-2 | Recirculation Ballot | 8/11/2008 | Quorum 93.21% Approval 76.28% | | | |
| 26 | Project 2008-11 | Request for Interpretation - VAR-002-1 - ICF Consulting - 0 | Initial Ballot | 9/8/2008 | Quorum 92.67% Approval 88.67% | | | |
| 27 | Project 2006-07 | IOC at a Standard - IROL-004-0 | Recirculation Ballot | 9/11/2008 | Quorum 79.29% Approval 79.29% | | | |
| 28 | Project 2007-14 | Permanent Changes to CT Timing Table - 0 | Initial Ballot | 9/11/2008 | Quorum 75.71% Approval 100.00% | | | |
| 29 | Project 2007-23 | Request for Interpretation - Blackstart Power - EOP-005 - 0 | Re-ballot | 9/18/2008 | Quorum 92.67% Approval 92.67% | | | |
| 30 | Project 2008-13 | Request for Interpretation - TOP-002-2 - Orlando Utilities Commission - 0 | Initial Ballot | 10/21/2008 | 10/30/2008 | Quorum 93.03% Approval 96.84% | | |
| 31 | Project 2006-01 | Project 2006-01 - FAC-003-1 - 0 | Initial Ballot | 10/27/2008 | 11/5/2008 | Quorum 92.67% Approval 92.67% | | |
| 32 | Project 2006-09 | Project 2006-09 - PRC-006-1 - Facility Ratings - 0 | Initial Ballot | 10/27/2008 | 11/5/2008 | Quorum 89.21% Approval 92.53% | | |
| 33 | Project 2006-07 | IOC at a Standard - IROL-009-1 - 0 | Recirculation Ballot | 10/28/2008 | 11/6/2008 | Quorum 93.03% Approval 83.71% | | |
| 34 | Project 2006-07 | Project 2006-07-IOC-MOD-028-0 - 0 | Initial Ballot | 11/1/2008 | 11/10/2008 | Quorum 93.77% Approval 93.77% | | |
| 35 | Project 2006-09 | Project 2006-09 - PRC-006-1 - Facility Ratings - 0 | Recirculation Ballot | 11/10/2008 | 11/19/2008 | Quorum 93.03% Approval 57.32% | | |
| 36 | Project 2008-13 | Request for Interpretation - TOP-002-2 - Orlando Utilities Commission - 0 | Recirculation Ballot | 11/10/2008 | 11/19/2008 | Quorum 92.67% Approval 87.87% | | |
| 37 | Project 2006-01 | Project 2006-01 - FAC-003-1 - 0 | Recirculation Ballot | 11/21/2008 | 12/11/2008 | Quorum 91.88% Approval 91.88% | | |
| 38 | Project 2008-15 | Request for Interpretation - CIP-006-1a - US Army CERL - 0 | Initial Ballot | 1/5/2009 | 1/14/2009 | Quorum 92.21% Approval 97.24% | | |
| 39 | Project 2008-14 | TOP-005-2 IRO Revisions - 0 | Initial Ballot | 1/5/2009 | 1/14/2009 | Quorum 92.67% Approval 92.67% | | |
| 40 | Project 2008-11 | Request for Interpretation - VAR-002-1 - ICF Consulting - 0 | Recirculation Ballot | 1/8/2009 | 1/17/2009 | Quorum 91.47% Approval 92.21% | | |
| 41 | Project 2006-07 | Project 2006-07-IOC-MOD-030-2 - 0 | Recirculation Ballot | 1/20/2009 | 1/29/2009 | Quorum 92.67% Approval 88.39% | | |
| 42 | Project 2008-16 | TOP-002-2 IRO Revisions - 0 | Recirculation Ballot | 1/28/2009 | 2/6/2009 | Quorum 92.03% Approval 92.03% | | |
| 43 | Project 2008-15 | Request for Interpretation - CIP-006-1a - US Army CERL - 0 | Recirculation Ballot | 1/8/2009 | 1/16/2009 | Quorum 92.67% Approval 92.67% | | |
| 44 | Project 2008-09 | Interpretation Request - BOP-001 - R1 - REC#2 - 0 | Initial Ballot | 2/17/2009 | 2/26/2009 | Quorum 89.67% Approval 89.67% | | |
| 45 | Project 2008-18 | Project 2008-18 Interpretation Attachment Events - 0 | Initial Ballot | 3/19/2009 | 3/28/2009 | Quorum 89.36% Approval 92.62% | | |
| 46 | Project 2008-06 | Project 2008-06 CIP-002-1 CIP-003-1 Revisions - 0 | Initial Ballot | 4/1/2009 | 4/10/2009 | Quorum 92.67% Approval 84.60% | | |
| 47 | Project 2009-10 | Project 2009-10 Interpretation - CIP0745 - PRC-005-1 R1 - 0 | Initial Ballot | 4/8/2009 | 4/17/2009 | Quorum 92.70% Approval 92.70% | | |
| 48 | Project 2009-02 | Project 2009-02 EOP-001, EOP-005, EOP-008 Series Restoration and Blackstart - 0 | Initial Ballot | 4/16/2009 | 4/25/2009 | Quorum 92.67% Approval 79.63% | | |
| 49 | Project 2008-06 | Project 2008-06 CIP-002-1 CIP-003-1 Revisions - 0 | Recirculation Ballot | 4/17/2009 | 4/27/2009 | Quorum 92.67% Approval 88.67% | | |
| 50 | Project 2008-18 | Project 2008-18 Interpretation Attachment Events - 0 | Recirculation Ballot | 4/17/2009 | 4/27/2009 | Quorum 91.93% Approval 92.62% | | |
| 51 | Project 2009-11 | Project 2009-11 Interpretation IRO17 Reliability Coordination Subcommittee RFI 10-1 - 0 | Initial Ballot | 4/21/2009 | 5/1/2009 | Quorum 89.67% Approval 88.77% | | |
| 52 | Project 2006-03 | Project 2006-03 EOP-005, EOP-006, EOP-008 Series Restoration and Blackstart - 0 | Recirculation Ballot | 5/8/2009 | 5/18/2009 | Quorum 92.08% Approval 92.08% | | |
| 53 | Project 2009-15 | Project 2009-15 Interpretation - IRO02 - IRO03-003-1, MOD-010-1 - 0 | Initial Ballot | 5/25/2009 | 6/4/2009 | Quorum 89.21% Approval 81.23% | | |
| 54 | Project 2009-11 | Project 2009-11 Interpretation IRO17 Reliability Coordination Subcommittee RFI 10-1 - 0 | Recirculation Ballot | 5/26/2009 | 6/5/2009 | Quorum 90.95% Approval 90.95% | | |
| 55 | Project 2009-13 | Project 2009-13 Interpretation - PerRforce - TPL-002-0b - 0 | Initial Ballot | 6/1/2009 | 6/11/2009 | Quorum 87.23% Approval 95.71% | | |
| 56 | Project 2009-08 | Project 2009-08 - Nuclear Plant Interface Coordination for Order 716 - 0 | Initial Ballot | 6/12/2009 | 6/22/2009 | Quorum 89.67% Approval 84.83% | | |
| 57 | Project 2008-14 | Project 2008-14 VSLs for CIP-002-1 through CIP-009-1 - 0 | Initial Ballot | 6/15/2009 | 6/24/2009 | Quorum 87.23% Approval 87.23% | | |
| 58 | Project 2008-14 | Project 2008-14 VSLs for CIP-002-1 through CIP-009-1 - 0 | Initial Ballot | 7/7/2009 | 7/16/2009 | Quorum 92.67% Approval 94.96% | | |
| 59 | Project 2009-15 | Project 2009-15 Interpretation - IRO02 - IRO03-003-1, MOD-010-1 - 0 | Recirculation Ballot | 7/8/2009 | 7/17/2009 | Quorum 89.21% Approval 81.23% | | |
| 60 | Project 2009-08 | Project 2009-08 - Nuclear Plant Interface Coordination for Order 716 - 0 | Recirculation Ballot | 7/22/2009 | 7/31/2009 | Quorum 87.23% Approval 84.83% | | |
| 61 | Project 2009-10 | Project 2009-10 Interpretation - CIP0745 - PRC-005-1 R1 - 0 | Recirculation Ballot | 7/24/2009 | 8/4/2009 | Quorum 91.93% Approval 95.65% | | |
| 62 | Project 2009-14 | Project 2009-14 Interpretation - PerRforce - TPL-002-0b - 0 | Initial Ballot | 7/24/2009 | 8/4/2009 | Quorum 92.34% Approval 95.71% | | |
| 63 | Project 2007-21 | Project 2007-21 TPL Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 85.71% Approval 90.84% | | |
| 64 | Project 2007-23 | Project 2007-23 EOP Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 92.67% Approval 88.12% | | |
| 65 | Project 2007-23 | Project 2007-23 PRC Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 84.21% Approval 88.28% | | |
| 66 | Project 2007-23 | Project 2007-23 IRO Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 92.67% Approval 90.11% | | |
| 67 | Project 2007-23 | Project 2007-23 MOD, FAC and NUC Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 85.71% Approval 92.67% | | |
| 68 | Project 2007-23 | Project 2007-23 CIP-002 and INT0 Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 89.84% Approval 87.63% | | |
| 69 | Project 2007-23 | Project 2007-23 CIP-003&-009 Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 89.84% Approval 85.70% | | |
| 70 | Project 2007-23 | Project 2007-23 BAs Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 94.49% Approval 94.49% | | |
| 71 | Project 2008-08 | Project 2008-08 EOP Violation Severity Levels - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 87.08% Approval 87.41% | | |
| 72 | Project 2009-17 | Project 2009-17 Interpretation - CIP-006-1a Patrick and Tri-State - PRC-005-1 and PRC-005-1 - 0 | Initial Ballot | 7/31/2009 | 8/10/2009 | Quorum 92.21% Approval 92.21% | | |
| 73 | RSAW 17 | Reliability Standards Development Procedure, Version 7 - June 2009 - 0 | Re-ballot | 7/27/2009 | 8/26/2009 | Quorum 94.81% Approval 71.76% | | |
| 74 | Project 2009-09 | Project 2009-09 - Interpretation - Cowlitz Exchange - CIP-002-1 - 0 | Initial Ballot | 8/6/2009 | 8/17/2009 | Quorum 92.67% Approval 68.92% | | |
| 75 | Project 2007-21 | Project 2007-21 TPL Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 91.86% Approval 90.84% | | |
| 76 | Project 2007-23 | Project 2007-23 BAs Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.08% Approval 89.61% | | |
| 77 | Project 2007-23 | Project 2007-23 CIP-003&-009 Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.41% Approval 85.70% | | |
| 78 | Project 2007-23 | Project 2007-23 CIP-002 and INT0 Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.67% Approval 88.04% | | |
| 79 | Project 2007-23 | Project 2007-23 IRO, PER, and TOP Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.67% Approval 88.71% | | |
| 80 | Project 2007-23 | Project 2007-23 IRO Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 91.86% Approval 90.11% | | |
| 81 | Project 2007-23 | Project 2007-23 CPS Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.21% Approval 90.91% | | |
| 82 | Project 2007-23 | Project 2007-23 TOP Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 92.21% Approval 88.16% | | |
| 83 | Project 2008-08 | Project 2008-08 EOP Violation Severity Levels - 0 | Recirculation Ballot | 8/17/2009 | 8/27/2009 | Quorum 91.70% Approval 87.41% | | |
| 84 | Order 706-B | Order 706-B Nuclear Implementation Plan - 0 | Initial Ballot | 8/26/2009 | 9/25/2009 | Quorum 92.21% Approval 87.37% | | |
| 85 | Project 2008-07 | Request for Interpretation - BoardStab Power - EOP-002 - 0 | Recirculation Ballot | 9/22/2009 | 10/1/2009 | Quorum 91.86% Approval 75.84% | | |
| 86 | Project 2009-12 | Project 2009-12 - Interpretation - PerRforce - CIP-002-1 - 0 | Initial Ballot | 9/17/2009 | 9/8/2009 | Quorum 94.64% Approval 94.64% | | |
| 87 | Project 2009-13 | Project 2009-13 - Interpretation - PerRforce - CIP-006-1 - 0 | Initial Ballot | 9/17/2009 | 9/8/2009 | Quorum 92.67% Approval 79.64% | | |
| 88 | Project 2009-18 | Project 2009-18 - Withdraw Texas Delegate EOP Waivers - 0 | Initial Ballot | 9/17/2009 | 9/8/2009 | Quorum 89.84% Approval 92.62% | | |
| 89 | Order 706-B | Order 706-B Nuclear Implementation Plan - 0 | Recirculation Ballot | 9/1/2009 | 9/10/2009 | Quorum 87.21% Approval 87.14% | | |
| 90 | RSAW 17 | Reliability Standards Development Procedure, Version 7 - June 2009 - 0 | Recirculation Ballot | 9/1/2009 | 9/10/2009 | Quorum 94.81% Approval 70.09% | | |
| 91 | Project 2008-06 | Project 2008-06 Cyber Security CIP6 and IDs for Version 2 CIP Standards - 0 | Initial Ballot | 9/10/2009 | 9/21/2009 | Quorum 87.05% Approval 87.05% | | |
| 92 | Project 2009-16 | Project 2009-16 - Interpretation - IRO17, CIP-0017 - 0 | Initial Ballot | 9/8/2009 | 9/21/2009 | Quorum 89.21% Approval 100.00% | | |
| 93 | Project 2006-04 | Project 2006-04 - Back-up Facility - EOP-008-1 - 0 | Initial Ballot | 9/16/2009 | 9/28/2009 | Quorum 92.89% Approval 92.89% | | |
| 94 | Project 2009-09 | Project 2009-09 - Interpretation - CleanEnergy - CIP-002-1 - 0 | Recirculation Ballot | 9/29/2009 | 10/8/2009 | Quorum 89.81% Approval 92.31% | | |
| 95 | Project 2008-10 | Project 2008-10 Interpretation of CIP-006-1 Request for Our Property Design | Initial Ballot | 9/30/2009 | 10/13/2009 | Quorum 92.67% Approval 92.67% | | |
| 96 | Project 2009-12 | Project 2009-12 - Interpretation - PerRforce - CIP-002-1 - 0 | Recirculation Ballot | 10/14/2009 | 10/26/2009 | Quorum 94.29% Approval 94.29% | | |
| 97 | Project 2008-06 | Project 2008-06 Cyber Security CIP5 and IDs for Version 2 CIP Standards - 0 | Recirculation Ballot | 11/2/2009 | 11/11/2009 | Quorum 89.70% Approval 94.24% | | |
| 98 | Project 2008-09 | Project 2008-09 - Interpretation - IROL - Revision 1 - 0 | Initial Ballot | 11/4/2009 | 11/14/2009 | Quorum 92.67% Approval 89.67% | | |
| 99 | Project 2009-21 | Project 2009-21 - Cyber Security Ninety-day Response - 0 | Initial Ballot | 11/30/2009 | 12/10/2009 | Quorum 89.81% Approval 89.81% | | |
| 100 | Project 2009-17 | Project 2009-17 - Interpretation - PJM Electric and Tri-State Response - 0 - 0 | Initial Ballot | 11/30/2009 | 12/7/2009 | Quorum 92.67% Approval 68.65% | | |
| 101 | Project 2009-20 | Project 2009-20 - Interpretation - BAs IRO-014 - Oneida Nation, Inc. - 0 | Initial Ballot | 11/30/2009 | 12/7/2009 | Quorum 87.21% Approval 87.21% | | |
| 102 | Project 2009-21 | Project 2009-21 - Cyber Security Ninety-day Response - 0 | Recirculation Ballot | 12/3/2009 | 12/14/2009 | Quorum 92.03% Approval 89.81% | | |
| 103 | Project 2009-23 | Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers - 0 | Initial Ballot | 12/3/2009 | 12/14/2009 | Quorum 94.11% Approval 94.11% | | |
| 104 | Project 2009-21 | Project 2009-21 - Interpretation - PerRforce - CIP-006-1 - 0 | Recirculation Ballot | 12/11/2009 | 12/22/2009 | Quorum 90.88% Approval 78.75% | | |
| 105 | Project 2009-24 | Project 2009-24 - Interpretation - TWRA - EOP-005-1 - 0 | Initial Ballot | 1/8/2010 | 1/19/2010 | Quorum 92.67% Approval 77.79% | | |
| 106 | Project 2009-25 | Project 2009-25 - Interpretation - BPA - BA-001-01 and BA-002-0 - 0 | Initial Ballot | 1/8/2010 | 1/19/2010 | Quorum 86.00% Approval 92.67% | | |
| 107 | Project 2009-26 | Project 2009-26 - Interpretation - IRO17 - CIP-0026-1 - 0 | Initial Ballot | 1/8/2010 | 1/19/2010 | Quorum 89.21% Approval 92.24% | | |
| 108 | Project 2009-06 | Project 2009-06 - Facility Ratings FAC-008-1 | Initial Ballot | 1/11/2010 | 1/21/2010 | Quorum 92.67% Approval 75.34% | | |
| 109 | Project 2009-27 | Project 2009-27 - Interpretation - TOP-002-2a for PNNM - 0 | Initial Ballot | 1/15/2010 | 1/25/2010 | Quorum 84.88% Approval 92.67% | | |
| 110 | Project 2009-28 | Project 2009-28 - Interpretation - EOP-001-1 and EOP-002-2 for NWPP - 0 | Initial Ballot | 1/15/2010 | 1/25/2010 | Quorum 87.58% Approval 91.78% | | |
| 111 | Project 2009-29 | Project 2009-29 - Interpretation - TOP-002-2a for NWPP - 0 | Initial Ballot | 1/15/2010 | 1/25/2010 | Quorum 84.28% Approval 92.67% | | |
| 112 | Project 2009-19 | Project 2009-19 - Interpretation - BAs IRO-4 Northern Fower Pool RSG - 0 | Initial Ballot | 1/15/2010 | 1/26/2010 | Quorum 89.81% Approval 49.84% | | |
| 113 | Project 2009-30 | Project 2009-30 - Interpretation - BAs IRO-4 - Oneida Nath, Inc. - 0 | Recirculation Ballot | 1/26/2010 | 2/26/2010 | Quorum 92.34% Approval 92.34% | | |
| 114 | Project 2009-31 | Project 2009-31 - Interpretation - PRC-005-1 for WECC - 0 | Initial Ballot | 2/1/2010 | 2/10/2010 | Quorum 89.51% Approval 98.74% | | |
| 115 | Project 2008-02 | Project 2008-02 - Assess Transmission Future Needs - TPL-005-0 - 0 | Initial Ballot | 2/18/2010 | 3/1/2010 | Quorum 92.67% Approval 85.80% | | |
| 116 | Project 2009-31 | Project 2009-31 - Interpretation - TOP-001-1 for NWPP - 0 | Initial Ballot | 3/5/2010 | 3/16/2010 | Quorum 89.24% Approval 92.67% | | |
| 117 | Project 2009-06 | Project 2009-06 - Facility Ratings FAC-008-1 | Recirculation Ballot | 3/8/2010 | 3/18/2010 | Quorum 92.51% Approval 78.13% | | |
| 118 | Project 2009-32 | Project 2009-32 - Interpretation - EOP-005-1 for NWPP - 0 | Re-ballot | 3/10/2010 | 3/19/2010 | Quorum 92.67% Approval 77.66% | | |
| 119 | Project 2009-19 | Project 2009-19 - Interpretation - CIP-004-1 - U.S. Army Corps of Engineers (Western U) - 0 | Initial Ballot | 3/29/2010 | 4/8/2010 | Quorum 89.61% Approval 92.67% | | |
| 120 | Project 2008-09 | Project 2008-09 - Interpretation - IROL - Revision 2 - 0 | Initial Ballot | 4/15/2010 | 4/26/2010 | Quorum 92.67% Approval 98.64% | | |
| 121 | RFW | Standards Process Manual Revisions - 0 | Initial Ballot | 4/23/2010 | 4/29/2010 | Quorum 87.58% Approval 87.58% | | |
| 122 | Project 2009-17 | Project 2009-17 - Interpretation - FAC-008-1 - 0 | Initial Ballot | 4/28/2010 | 5/10/2010 | Quorum 92.01% Approval 92.01% | | |
| 123 | RFW | Standards Process Manual Revisions - 0 | Recirculation Ballot | 4/30/2010 | 5/10/2010 | Quorum 92.67% Approval 88.09% | | |
| 124 | Project 2010-11 | Project 2010-11 BAL-005 - Balancing Authority Control - 0 | Initial Ballot | 5/17/2010 | 5/27/2010 | Quorum 89.81% Approval 92.67% | | |
| 125 | Project 2010-09 | Project 2010-09 NUC Implementation Plans for CIP Version 2 and Version 3 - 0 | Initial Ballot | 5/18/2010 | 6/1/2010 | Quorum 89.81% Approval 90.81% | | |
| 126 | Project 2010-09 | Project 2010-09 NUC Implementation Plans for CIP Version 2 and Version 3 - 0 | Recirculation Ballot | 6/11/2010 | 7/2/2010 | Quorum 89.24% Approval 92.67% | | |
| 127 | Project 2008-04 | Project 2008-04 - Backup Facilities - Revision 1 - 0 | Initial Ballot | 6/15/2010 | 7/8/2010 | Quorum 89.81% Approval 75.81% | | |
| 128 | Project 2008-08 | Project 2008-08 - Reliability Coordination - Transmission Loading Relief - 0 | Initial Ballot | 6/15/2010 | 7/8/2010 | Quorum 89.81% Approval 85.88% | | |
| 129 | Project 2007-01 | Project 2007-01 Underfrequency Load Shedding (PRC-006-1 and EOP-003-1 | Initial Ballot | 7/7/2010 | 12/7/2010 | Quorum 90.94% Approval 92.67% | | |
| 130 | Project 2007-17 | Project 2007-17 Protection System Maintenance and Testing (PRC-005-1 | Initial Ballot | 7/8/2010 | 7/17/2010 | Quorum 92.21% Approval 72.91% | | |
| 131 | Project 2007-17 | Project 2007-17 Protection System Maintenance and Testing (PRC-005-1) | Non-binding Poll | 7/8/2010 | 7/17/2010 | Quorum 92.21% Approval 60.00% | | |
| 132 | Project 2007-17 | Project 2007-17 Protection System Maintenance and Testing Protection System definition | Initial Ballot | 7/8/2010 | 7/17/2010 | Quorum 87.21% Approval 87.21% | | |
| 133 | Project 2007-07 | Project 2007-07 Vegetation Management (FAC-003-1) | Initial Ballot | 7/9/2010 | 7/19/2010 | Quorum 92.67% Approval 92.67% | | |
| 134 | Project 2008-04 | Project 2008-04 - Backup Facilities - Revision 1 - 0 | Recirculation Ballot | 7/16/2010 | 7/26/2010 | Quorum 92.03% Approval 92.03% | | |
| 135 | Project 2007-17 | Project 2007-17 Protection System Maintenance Protection System definition | Successive Ballot | 7/23/2010 | 8/2/2010 | Quorum 90.70% Approval 58.81% | | |
| 136 | Project 2007-01 | Project 2007-01 Underfrequency Load Shedding (PRC-006-1 and EOP-003-1 | Successive Ballot | 7/16/2010 | 8/5/2010 | Quorum 92.03% Approval 92.67% | | |
| 137 | Project 2008-08 | Project 2008-08 - Reliability Coordination - Transmission Loading Relief - 0 | Recirculation Ballot | 8/20/2010 | 9/30/2010 | Quorum 90.81% 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 92.67% Approval 75.17% | | |
| 139 | Project 2010-15 | Project 2010-15 - Urgent Action Revisions to CIP-003-3 | Initial Ballot | 9/17/2010 | 9/27/2010 | Quorum 96.46% Approval 96.46% | | |
| 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 92.71% Approval 92.71% | | |
| 141 | Project 2007-17 | Project 2007-17 Protection System Maintenance Protection System definition | Successive Ballot | 10/1/2010 | 10/14/2010 | Quorum 92.21% Approval 92.21% | | |
| 142 | Project 2008-09 | Project 2008-09 - Interpretation - IROL - Revision 1 - 0 | Recirculation Ballot | 10/8/2010 | 10/14/2010 | Quorum 88.21% Approval 92.67% | | |
| 143 | Project 2009-28 | Project 2009-28 - Interpretation - PRC-005-1 and EOP-001-1 for NWPP - 0 | Recirculation Ballot | 10/5/2010 | 10/15/2010 | Quorum 92.03% Approval 92.78% | | |
| 144 | Project 2009-27 | Project 2009-27 - Interpretation - EOP-005-1 for NWPP - 0 | Recirculation Ballot | 10/8/2010 | 10/18/2010 | Quorum 92.21% Approval 92.67% | | |
| 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 92.03% Approval 89.87% | | |
| 146 | Project 2008-06 | Project 2008-06 Cyber Security TID Filename ECP Standards - 0 | Initial Ballot | 10/20/2010 | 11/3/2010 | Quorum 92.03% Approval 92.03% | | |
| 147 | Project 2010-03 | Project 2010-03 PRC-012-0 Planning Tutorial Capability - 0 | Initial Ballot | 10/20/2010 | 11/3/2010 | Quorum 88.04% Approval 89.84% | | |
| 148 | 2010 SPM | 2010 Standard Processes Manual (Proposed Changes) - 0 | Initial Ballot | 10/28/2010 | 11/7/2010 | Quorum 92.67% Approval 92.71% | | |
| 149 | Project 2007-17 | Project 2007-17 Protection System Maintenance Protection System definition | Recirculation Ballot | 11/1/2010 | 11/11/2010 | Quorum 89.61% Approval 92.21% | | |
| 150 | 2010 SPM | 2010 Standard Processes Manual (Proposed Changes) - 0 | Recirculation Ballot | 11/8/2010 | 11/12/2010 | Quorum 87.58% Approval 92.88% | | |
| 151 | Project 2008-17 | Project 2008-17 - Interpretation CIP-002-1 for Duke Energy - 0 | Recirculation Ballot | 11/10/2010 | 11/20/2010 | Quorum 92.67% Approval 82.61% | | |
| 152 | Project 2008-06 | Project 2008-06 Cyber Security TID Filename ECP Standards - 0 - 0 | Initial Ballot | 11/5/2010 | 12/15/2010 | Quorum 87.07% Approval 92.67% | | |
| 153 | Project 2010-15 | Project 2010-15 - Expedited Action Revisions to CIP-003-3 | Initial Ballot | 11/5/2010 | 11/11/2010 | Quorum 92.88% Approval 92.88% | | |
| 154 | Project 2007-04 | Project 2007-04 - Certifying System Operators- PER-003-1 | Recirculation Ballot | 11/5/2010 | 11/15/2010 | Quorum 90.51% Approval 80.51% | | |
| 155 | Project 2010-13 | Project 2010-13 - Rev Capability Order - PRC-012 | Initial Ballot | 12/7/2010 | 12/16/2010 | Quorum 88.88% Approval 51.51% | | |
| 156 | Project 2007-17 | Project 2007-17 Protection System Maintenance and Testing (PRC-005-1 | Successive Ballot | 11/16/2010 | 11/26/2010 | Quorum 92.21% Approval 92.21% | | |
| 157 | Project 2007-17 | Project 2007-17 Protection System Maintenance and Testing (PRC-005-1) | Non-binding Poll | 11/16/2010 | 11/26/2010 | Quorum 70.00% Approval 52.00% | | |
| 158 | Project 2008-06 | Project 2008-06 Cyber Security TID Filename ECP Standards - 0 - 0 | Recirculation Ballot | 11/30/2010 | 12/30/2010 | Quorum 87.07% Approval 80.92% | | |
| 159 | Project 2010-11 | Project 2010-11 TPL Table 1 Footnote B Edit - 0 | Recirculation Ballot | 12/27/2010 | 1/6/2011 | Quorum 90.61% Approval 92.67% | | |
| 160 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-002-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 22.00% | Oppose 5/3/2011 | |
| 161 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-003-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 22.00% | Oppose 5/3/2011 | |
| 162 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-004-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 22.00% | Oppose 5/3/2011 | |
| 163 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-005-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 28.04% | Oppose 5/3/2011 | |
| 164 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-006-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 22.00% | Oppose 5/3/2011 | |
| 165 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-007-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 22.00% | Oppose 5/3/2011 | |
| 166 | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 CIP-008-1 | Initial Ballot | 1/14/2011 | 1/24/2011 | Quorum 92.67% Approval 18.39% | Oppose 5/3/2011 | |

List to Ballot Results
https://standards.nerc.net/Ballots.aspx
(clicking in the column to the right of "Ballot Period" opens links to the Ballot Results)

| Line | Project | Ballot Type | Start Date | End Date (Actual Ballot Closed) | Ballot Results | Recommendation / Date | Have NERC Voted | Comments |
|---|---|---|---|---|---|---|---|---|
| 167 | Project 2008-06 | Initial Ballot | 11/14/2011 | 1/4/2012 | Quorum: 93.61% Approve: 79.41% | Oppose 12/20/11 | | |
| 168 | Project 2008-06 | Initial Ballot | 11/14/2011 | 1/4/2012 | Quorum: 93.61% Approve: 35.61% | Oppose 12/13/11 | | |
| 169 | Project 2008-06 | Initial Ballot | 11/14/2011 | 1/4/2012 | Quorum: 93.61% Approve: 84.88% | Oppose 12/13/11 | | |
| 170 | Project 2008-06 | Initial Ballot | 11/14/2011 | 1/4/2012 | Quorum: 93.21% Approve: 79.41% | Oppose 12/20/11 | | |
| 171 | Project 2008-06 | Initial Ballot | 11/14/2011 | 1/4/2012 | Quorum: 92.26% Approve: 25.64% | Oppose 12/13/11 | | |
| 172 | Project 2010-03 | Initial Ballot | 11/30/2010 | 1/4/2011 | Quorum: 91.41% Approve: 92.31% | | | |
| 173 | Project 2010-03 | Recirculation Ballot | 1/14/2011 | 1/23/2011 | Quorum: 90.01% Approve: 68.96% | | | |
| 174 | Project 2010-11 | Recirculation Ballot | 1/26/2011 | 1/5/2011 | Quorum: 87.97% Approve: 86.79% | Support 1/5/11 | | |
| 175 | Project 2010-13 | Successive Ballot | 1/26/2011 | 2/14/2011 | Quorum: 83.91% Approve: 72.00% | Support 2/10/11 | | |
| 176 | Project 2007-23 | Non-Binding Poll | 1/8/2011 | 2/22/2011 | Quorum: 78.00% Approve: 72.00% | Support 2/22/11 | | |
| 177 | Project 2007-07 | Successive Ballot | 2/18/2011 | 2/28/2011 | Quorum: 79.28% Approve: 75.00% | Support 2/28/11 | | |
| 178 | Project 2010-13 | Recirculation Ballot | 2/16/2011 | 3/8/2011 | Quorum: 87.21% Approve: 68.84% | Support 3/11/11 | | |
| 179 | Project 2008-06 | Initial Ballot | 2/25/2011 | 3/7/2011 | Quorum: 79.68% Approve: 43.63% | Oppose 3/11/11 | | |
| 180 | Project 2010-15 | Successive Ballot | 4/19/2011 | 4/28/2011 | Quorum: 79.68% Approve: 75.00% | Oppose 5/12/11 | | |
| 181 | Project 2009-06 | Initial Ballot | 4/21/2011 | 5/3/2011 | Quorum: 80.81% Approve: 48.74% | Abstain 5/26/11 | | |
| 182 | Project 2009-06 | Non-binding Poll | 4/21/2011 | 5/2/2011 | Quorum: 80.81% Approve: 71.84% | | | |
| 183 | Project 2007-17 | Successive Ballot | 5/5/2011 | 5/12/2011 | Quorum: 78.21% Approve: 77.00% | No Recommendation | | |
| 184 | Project 2007-17 | Non-binding Poll | 5/5/2011 | 5/12/2011 | Quorum: 77.00% Approve: 66.00% | | | |
| 185 | Project 2009-06 | Recirculation Ballot | 5/12/2011 | 5/23/2011 | Quorum: 81.21% Approve: 47.37% | Support 5/23/11 | | |
| 186 | Project 2006-02 | Successive Ballot | 5/18/2011 | 5/31/2011 | Quorum: 52.27% Approve: 71.84% | | | |
| 187 | Project 2006-02 | Non-binding Poll | 5/18/2011 | 5/31/2011 | Quorum: 66.79% Approve: 71.84% | | | |
| 188 | Project 2007-02 | Initial Ballot | 5/31/2011 | 6/9/2011 | Quorum: 68.87% Approve: 48.64% | Oppose 6/21/11 | | |
| 189 | Project 2007-02 | Non-binding Poll | 5/31/2011 | 6/9/2011 | Quorum: 68.87% Approve: 41.00% | | | |
| 190 | Project 2007-17 | Recirculation Ballot | 6/20/2011 | 6/30/2011 | Quorum: 81.87% Approve: 76.47% | Support 6/30/11 | | |
| 191 | Project 2007-17 | Non-binding Poll | 6/20/2011 | 6/30/2011 | Quorum: 72.81% Approve: 60.00% | | | |
| 192 | Project 2006-02 | Recirculation Ballot | 7/11/2011 | 7/21/2011 | Quorum: 75.67% Approve: 75.67% | | | |
| 193 | Project 2006-06 | Recirculation Ballot | 7/15/2011 | 7/25/2011 | Quorum: 94.11% Approve: 75.00% | Support 7/25/11 | | |
| 194 | Project 2006-06 | Recirculation Ballot | 7/15/2011 | 7/25/2011 | Quorum: 75.17% Approve: 75.17% | Support 7/25/11 | | |
| 195 | Project 2006-06 | Recirculation Ballot | 7/15/2011 | 7/25/2011 | Quorum: 92.31% Approve: 75.00% | Support 7/25/11 | | |
| 196 | Project 2006-06 | Recirculation Ballot | 7/15/2011 | 7/25/2011 | Quorum: 75.87% Approve: 60.00% | | | |
| 197 | Project 2006-06 | Non-binding Poll | 7/15/2011 | 7/25/2011 | Quorum: 75.87% Approve: 60.00% | | | |
| 198 | Project 2006-06 | Recirculation Ballot | 7/15/2011 | 7/25/2011 | Quorum: 71.67% Approve: 60.00% | | | |
| 199 | Project 2007-09 | Initial Ballot | 7/21/2011 | 8/1/2011 | Quorum: 78.75% Approve: 46.51% | No Consensus 7/28/11 | | |
| 200 | Project 2007-09 | Non-binding Poll | 7/21/2011 | 8/1/2011 | Quorum: 78.75% Approve: 38.00% | | | |
| 201 | Project 2007-09 | Initial Ballot | 7/21/2011 | 8/1/2011 | Quorum: 69.87% Approve: 18.23% | No Consensus 7/28/11 | | |
| 202 | Project 2007-09 | Non-binding Poll | 7/21/2011 | 8/1/2011 | Quorum: 69.87% Approve: 20.00% | | | |
| 203 | Project 2007-17 | Initial Ballot | 8/19/2011 | 8/29/2011 | Quorum: 84.86% Approve: 84.21% | Support 8/31/11 | | |
| 204 | Project 2007-17 | Non-binding Poll | 8/19/2011 | 8/29/2011 | Quorum: 83.14% Approve: 68.68% | | | |
| 205 | Project 2010-17 | Initial Ballot | 9/8/2011 | 10/20/2011 | Quorum: 81.21% Approve: 71.87% | No Consensus 10/31/11 | | |
| 206 | Project 2010-17 | Initial Ballot | 9/8/2011 | 10/20/2011 | Quorum: 80.01% Approve: 80.01% | No Consensus 10/31/11 | | |
| 207 | Project 2007-07 | Recirculation Ballot | 10/6/2011 | 10/13/2011 | Quorum: 83.21% Approve: 88.35% | Support 10/13/11 | | |
| 208 | Project 2011-INT-01 | Initial Ballot | 5/27/2011 | 11/14/2011 | Quorum: 80.01% Approve: 80.01% | Support 11/14/11 | | |
| 209 | Project 2009-22 | Initial Ballot | 6/8/2011 | 11/17/2011 | Quorum: 55.28% Approve: 85.00% | Support 11/30/11 | | |
| 210 | Project 2010-07 | Initial Ballot | 11/8/2011 | 11/18/2011 | Quorum: 80.01% Approve: 80.01% | Support 11/30/11 | | |
| 211 | Project 2010-07 | Initial Ballot | 11/8/2011 | 11/18/2011 | Quorum: 80.08% Approve: 81.71% | Support 11/30/11 | | |
| 212 | Project 2010-07 | Initial Ballot | 11/8/2011 | 11/18/2011 | Quorum: 80.01% Approve: 85.01% | Support 11/30/11 | | |
| 213 | Project 2010-07 | Initial Ballot | 11/8/2011 | 11/18/2011 | Quorum: 79.29% Approve: 85.01% | Support 11/30/11 | | |
| 214 | Project 2008-10 | Successive Ballot | 11/11/2011 | 11/21/2011 | Quorum: 83.01% Approve: 65.00% | Support 11/30/11 | | |
| 215 | Project 2010-17 | Recirculation Ballot | 11/16/2011 | 11/21/2011 | Quorum: 83.01% Approve: 83.01% | Support 11/30/11 | | |
| 216 | Project 2010-17 | Definition of Bulk Electric System Detailed Information to Support BES Exceptions Request | Recirculation Ballot | 11/18/2011 | 11/21/2011 | Quorum: 79.01% Approve: 79.01% | Support 11/30/11 | |
| 217 | Project 2007-12 | Initial Ballot | 11/30/2011 | 12/8/2011 | Quorum: 83.01% Approve: 83.01% | Oppose 12/8/11 | | |
| 218 | Project 2007-12 | Non-binding Poll | 11/30/2011 | 12/8/2011 | Quorum: 83.01% Approve: 36.00% | | | |
| 219 | Project 2009-01 | Initial Ballot | 12/2/2011 | 12/12/2011 | Quorum: 87.87% Approve: 87.87% | Oppose 12/20/11 | | |
| 220 | Project 2009-01 | Non-binding Poll | 12/2/2011 | 12/12/2011 | Quorum: 87.87% Approve: 65.00% | | | |
| 221 | Project 2008-10 | Recirculation Ballot | 12/8/2011 | 12/18/2011 | Quorum: 90.01% Approve: 90.01% | Support 12/20/11 | | |
| 222 | Project 2011-INT-01 | Recirculation Ballot | 12/12/2011 | 12/22/2011 | Quorum: 90.28% Approve: 90.28% | Support 12/30/11 | | |
| 223 | Project 2009-22 | Recirculation Ballot | 12/14/2011 | 12/23/2011 | Quorum: 90.28% Approve: 90.28% | Support 12/30/11 | | |
| 224 | Project 2010-07 | Recirculation Ballot | 12/14/2011 | 12/23/2011 | Quorum: 90.84% Approve: 90.28% | Support 12/30/11 | | |
| 225 | Project 2010-07 | Recirculation Ballot | 12/14/2011 | 12/23/2011 | Quorum: 90.84% Approve: 85.84% | Support 12/30/11 | | |
| 226 | Project 2010-07 | Recirculation Ballot | 12/14/2011 | 12/23/2011 | Quorum: 89.91% Approve: 89.91% | Support 12/30/11 | | |
| 227 | Project 2010-07 | Recirculation Ballot | 12/14/2011 | 12/23/2011 | Quorum: 90.01% Approve: 90.01% | Support 12/30/11 | | |
| 228 | Project 2007-03 | Successive Ballot | 1/5/2012 | 1/12/2012 | Quorum: 92.01% Approve: 92.01% | Support 1/12/12 | | |
| 229 | Project 2007-03 | Successive Ballot | 1/5/2012 | 1/12/2012 | Quorum: 92.01% Approve: 92.01% | Support 1/12/12 | | |
| 230 | Project 2007-03 | Successive Ballot | 1/5/2012 | 1/12/2012 | Quorum: 92.01% Approve: 78.91% | Support 1/12/12 | | |
| 231 | Project 2010-07 | Non-binding Poll | 1/6/2012 | 1/13/2012 | Quorum: 92.01% Approve: 92.01% | | | |
| 232 | Project 2007-03 | Non-binding Poll | 1/6/2012 | 1/16/2012 | Quorum: 74.91% Approve: 71.91% | | | |
| 233 | Project 2007-03 | Non-binding Poll | 1/6/2012 | 1/16/2012 | Quorum: 74.91% Approve: 67.91% | | | |
| 234 | Project 2007-03 | Non-binding Poll | 1/6/2012 | 1/16/2012 | Quorum: 92.01% Approve: 77.91% | | | |
| 235 | Project 2006-06 | Successive Ballot | 1/30/2012 | 2/8/2012 | Quorum: 92.83% Approve: 53.84% | Oppose 2/13/12 | | |
| 236 | Project 2006-06 | Successive Ballot | 1/30/2012 | 2/8/2012 | Quorum: 92.21% Approve: 92.21% | Support 2/13/12 | | |
| 237 | Project 2006-06 | Successive Ballot | 1/30/2012 | 2/8/2012 | Quorum: 92.83% Approve: 85.21% | Support 2/13/12 | | |
| 238 | Project 2006-06 | Successive Ballot | 1/30/2012 | 2/8/2012 | Quorum: 92.21% Approve: 71.83% | Support 2/13/12 | | |
| 239 | Project 2006-06 | Non-binding Poll | 1/30/2012 | 2/8/2012 | Quorum: 92.83% Approve: 90.86% | | | |
| 240 | Project 2006-06 | Non-binding Poll | 1/30/2012 | 2/8/2012 | Quorum: 92.21% Approve: 77.77% | | | |
| 241 | Project 2009-01 | Successive Ballot | 2/14/2012 | 2/23/2012 | Quorum: 92.83% Approve: 78.61% | Support 2/23/12 | | |
| 242 | Project 2010-INT-05 | Recirculation Ballot | 4/14/2012 | 4/23/2012 | Quorum: 90.01% Approve: 90.01% | Support 5/10/12 | | |
| 243 | Project 2011-INT-02 | Initial Ballot | 4/14/2012 | 4/23/2012 | Quorum: 90.01% Approve: 63.00% | Support 5/10/12 | | |
| 244 | Project 2007-09 | Successive Ballot | 5/19/2012 | 6/28/2012 | Quorum: 81.01% Approve: 81.01% | | | |
| 245 | Project 2007-09 | Successive Ballot | 5/19/2012 | 6/28/2012 | Quorum: 80.88% Approve: 61.00% | | | |
| 246 | Project 2007-17 | Successive Ballot | 5/19/2012 | 6/28/2012 | Quorum: 84.31% Approve: 84.31% | Support 5/23/12 | | |
| 247 | Project 2007-17 | Non-binding Poll | 5/19/2012 | 6/28/2012 | Quorum: 84.31% Approve: 68.31% | | | |
| 248 | Project 2010-07 | Successive Ballot | 5/30/2012 | 6/8/2012 | Quorum: 90.01% Approve: 90.01% | Support 6/11/12 | | |
| 249 | Project 2010-07 | Successive Ballot | 5/30/2012 | 6/8/2012 | Quorum: 89.15% Approve: 89.15% | Support 6/11/12 | | |
| 250 | Project 2007-09 | Initial Ballot | 4/6/2012 | 4/16/2012 | Quorum: 69.26% Approve: 69.26% | Oppose 4/16/12 | | |
| 251 | Project 2007-09 | Initial Ballot | 4/6/2012 | 4/16/2012 | Quorum: 69.26% Approve: 61.00% | Oppose 4/16/12 | | |
| 252 | Project 2007-09 | Initial Ballot | 4/6/2012 | 4/16/2012 | Quorum: 68.84% Approve: 68.84% | Oppose 4/16/12 | | |
| 253 | Project 2007-09 | Non-binding Poll | 4/6/2012 | 4/16/2012 | Quorum: 68.84% Approve: 48.70% | Oppose 4/16/12 | | |
| 254 | Project 2007-09 | Non-binding Poll | 4/6/2012 | 4/16/2012 | Quorum: 68.84% Approve: 38.00% | | | |
| 255 | Project 2007-09 | Non-binding Poll | 4/6/2012 | 4/16/2012 | Quorum: 68.84% Approve: 38.00% | | | |
| 256 | Project 2010-07 | Initial Ballot | 4/6/2012 | 4/16/2012 | Quorum: 68.85% Approve: 68.85% | Support 4/16/12 | | |
| 257 | Project 2010-07 | Recirculation Ballot | 4/16/2012 | 4/26/2012 | Quorum: 90.01% Approve: 90.01% | Support 5/10/12 | | |
| 258 | Project 2007-03 | Successive Ballot | 4/5/2012 | 4/12/2012 | Quorum: 92.01% Approve: 92.01% | Support 4/12/12 | | |
| 259 | Project 2007-03 | Successive Ballot | 4/5/2012 | 4/12/2012 | Quorum: 92.01% Approve: 92.01% | Support 4/12/12 | | |
| 260 | Project 2007-03 | Successive Ballot | 4/5/2012 | 4/12/2012 | Quorum: 92.01% Approve: 78.91% | Support 4/12/12 | | |
| 261 | Project 2007-03 | Non-binding Poll | 4/5/2012 | 4/15/2012 | Quorum: 92.01% Approve: 92.01% | | | |
| 262 | Project 2009-26 | Successive Ballot | 4/30/2012 | 5/9/2012 | Quorum: 92.83% Approve: 53.84% | Oppose 5/14/12 | | |
| 263 | Project 2010-INT-05 | Recirculation Ballot | 4/30/2012 | 4/30/2012 | Quorum: 92.83% Approve: 92.83% | Support 5/14/12 | | |
| 264 | Project 2010-07 | Recirculation Ballot | 4/30/2012 | 5/9/2012 | Quorum: 92.21% Approve: 87.44% | | | |
| 265 | Project 2010-07 | Recirculation Ballot | 4/30/2012 | 5/9/2012 | Quorum: 92.21% Approve: 87.21% | | | |
| 266 | Project 2010-07 | Recirculation Ballot | 4/30/2012 | 5/9/2012 | Quorum: 90.44% Approve: 81.01% | | | |
| 267 | Project 2007-03 | Recirculation Ballot | 6/27/2012 | 7/6/2012 | Abstain Approve: 76.84% | Abstain 6/29/12 | | |
| 268 | Project 2007-03 | Recirculation Ballot | 6/27/2012 | 7/6/2012 | Quorum: 75.26% Approve: 75.26% | Support 6/29/12 | | |
| 269 | Project 2007-03 | Recirculation Ballot | 6/27/2012 | 7/6/2012 | Quorum: 76.38% Approve: 60.71% | Support 6/29/12 | | |
| 270 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 94.61% Approve: 94.61% | Abstain 5/23/12 | | |
| 271 | Project 2008-06 | Recirculation Ballot | 5/11/2012 | 5/21/2012 | Quorum: 87.87% Approve: 60.05% | Abstain 5/23/12 | | |
| 272 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 94.61% Approve: 68.81% | Abstain 5/23/12 | | |
| 273 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 94.98% Approve: 94.98% | Abstain 5/23/12 | | |
| 274 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 87.87% Approve: 58.50% | Abstain 5/23/12 | | |
| 275 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 87.74% Approve: 87.74% | Abstain 5/23/12 | | |
| 276 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 86.21% Approve: 57.01% | Abstain 5/23/12 | | |
| 277 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 87.01% Approve: 60.08% | Abstain 5/23/12 | | |
| 278 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 86.28% Approve: 86.28% | Abstain 5/23/12 | | |
| 279 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 86.28% Approve: 58.81% | Abstain 5/23/12 | | |
| 280 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 86.21% Approve: 86.21% | Abstain 5/23/12 | | |
| 281 | Project 2008-06 | Successive Ballot | 5/11/2012 | 5/21/2012 | Quorum: 84.85% Approve: 47.88% | Abstain 5/23/12 | | |
| 282 | Project 2009-01 | Successive Ballot | 5/15/2012 | 5/24/2012 | Quorum: 79.69% Approve: 65.31% | | | |
| 283 | Project 2009-01 | Successive Ballot | 5/15/2012 | 5/24/2012 | Quorum: 79.69% Approve: 79.69% | | | |
| 284 | Project 2007-02 | Initial Ballot | 4/11/2012 | 4/20/2012 | Quorum: 83.21% Approve: 83.21% | Oppose 4/13/12 | | |
| 285 | Project 2007-02 | Non-binding Poll | 4/11/2012 | 4/20/2012 | Quorum: 83.21% Approve: 68.00% | | | |
| 286 | Project 2007-17 | Successive Ballot | 4/18/2012 | 4/27/2012 | Quorum: 79.84% Approve: 79.84% | | | |
| 287 | Project 2007-17 | Non-binding Poll | 4/18/2012 | 4/27/2012 | Quorum: 79.84% Approve: 70.01% | | | |
| 288 | Project 2011-INT-02 | Successive Ballot | 5/18/2012 | 5/27/2012 | Quorum: 92.83% Approve: 92.83% | Support 6/4/12 | | |
| 289 | Project 2007-06 | Initial Ballot | 6/26/2012 | 7/6/2012 | Quorum: 84.83% Approve: 63.61% | Oppose 7/11/12 | | |
| 290 | Project 2007-06 | Non-binding Poll | 6/26/2012 | 7/6/2012 | Quorum: 84.83% Approve: 52.00% | | | |
| 291 | Project 2006-06 | Recirculation Ballot | 6/27/2012 | 7/6/2012 | Quorum: 83.21% Approve: 83.21% | | | |
| 292 | Project 2006-06 | Recirculation Ballot | 6/27/2012 | 7/6/2012 | Quorum: 83.21% Approve: 83.21% | | | |
| 293 | Project 2006-06 | Non-binding Poll | 6/27/2012 | 7/6/2012 | Quorum: 84.28% Approve: 84.28% | | | |
| 294 | Project 2006-06 | Non-binding Poll | 6/27/2012 | 7/6/2012 | Quorum: 83.87% Approve: 68.81% | | | |
| 295 | Project 2006-06 | Successive Ballot | 6/27/2012 | 7/6/2012 | Quorum: 83.21% Approve: 71.00% | No Consensus 7/11/12 | | |
| 296 | Project 2006-06 | Non-binding Poll | 6/27/2012 | 7/11/2012 | Quorum: 79.67% Approve: 79.67% | | | |
| 297 | Project 2011-INT-02 | Recirculation Ballot | 7/18/2012 | 7/27/2012 | Quorum: 90.87% Approve: 90.87% | Support 8/06/12 | | |
| 298 | Project 2011-INT-02 | Non-binding Poll | 7/18/2012 | 7/27/2012 | Quorum: 90.87% Approve: 80.00% | | | |
| 299 | Project 2010-INT-01 | Initial Ballot | 7/20/2012 | 7/30/2012 | Quorum: 90.89% Approve: 75.00% | Oppose 7/30/12 | | |
| 300 | Project 2010-INT-01 | Non-binding Poll | 7/20/2012 | 7/30/2012 | Quorum: 90.89% Approve: 70.07% | | | |
| 301 | Project 2012-08-1 | Initial Ballot | 7/26/2012 | 8/15/2012 | Quorum: 83.21% Approve: 83.21% | Oppose 8/15/12 | | |
| 302 | Project 2007-17 | Successive Ballot | 8/17/2012 | 8/27/2012 | Quorum: 78.71% Approve: 80.21% | Support 8/27/12 | | |
| 303 | Project 2009-19 | Successive Ballot | 8/23/2012 | 9/4/2012 | Quorum: 79.21% Approve: 79.21% | Support 9/11/12 | | |
| 304 | Project 2010-01-1 | Initial Ballot | 8/29/2012 | 9/7/2012 | Quorum: 78.71% Approve: 27.08% | Support 9/11/12 | | |
| 305 | Project 2010-01-1 | Non-binding Poll | 8/29/2012 | 9/7/2012 | Quorum: 78.71% Approve: 47.00% | | | |
| 306 | Project 2006-06 | Recirculation Ballot | 9/6/2012 | 9/17/2012 | Quorum: 90.01% Approve: 90.01% | | | |
| 307 | Project 2007-02 | Successive Ballot | 9/11/2012 | 9/20/2012 | Quorum: 77.95% Approve: 55.57% | Support 9/21/12 | | |
| 308 | Project 2007-02 | Non-binding Poll | 9/11/2012 | 9/20/2012 | Quorum: 77.95% Approve: 64.67% | | | |
| 309 | Project 2010-INT-01 | Recirculation Ballot | 9/12/2012 | 9/21/2012 | Quorum: 90.01% Approve: 90.01% | | | |
| 310 | Project 2009-01 | Successive Ballot | 9/18/2012 | 9/27/2012 | Quorum: 75.95% Approve: 55.68% | No Consensus 9/27/12 | | |
| 311 | Project 2009-01 | Non-binding Poll | 9/18/2012 | 9/27/2012 | Quorum: 75.95% Approve: 70.00% | | | |
| 312 | Project 2009-19 | Recirculation Ballot | 9/28/2012 | 10/8/2012 | Quorum: 69.21% Approve: 90.01% | Support 10/10/12 | | |
| 313 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.28% Approve: 90.28% | Support 10/24/12 | | |
| 314 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.87% Approve: 89.90% | Support 10/24/12 | | |
| 315 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.87% Approve: 83.00% | Support 10/24/12 | | |
| 316 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 89.98% Approve: 89.98% | Support 10/24/12 | | |
| 317 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.68% Approve: 92.11% | Support 10/24/12 | | |
| 318 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.87% Approve: 87.71% | Support 10/24/12 | | |
| 319 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.28% Approve: 90.28% | Support 10/24/12 | | |
| 320 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.68% Approve: 91.70% | Support 10/24/12 | | |
| 321 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.68% Approve: 90.68% | Support 10/24/12 | | |
| 322 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.68% Approve: 91.00% | Support 10/24/12 | | |
| 323 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 90.28% Approve: 90.28% | Support 10/24/12 | | |
| 324 | Project 2008-06 | Successive Ballot | 10/2/2012 | 10/22/2012 | Quorum: 79.21% Approve: 71.00% | Support 10/24/12 | | |
| 325 | IPW SPR | Standard Processes Manual Revisions to Implement SPIG Recommendations | Initial Ballot | 10/3/2012 | 10/12/2012 | Quorum: 81.01% Approve: 81.01% | Support 10/24/12 | |
| 326 | dRFs and VRLs | Revisions to Outstanding dRFs and VRLs | Non-binding Poll | 10/10/2012 | 10/23/2012 | Quorum: 79.57% Approve: 79.57% | | |
| 327 | Project 2007-17 | Successive Ballot | 10/15/2012 | 10/25/2012 | Quorum: 81.88% Approve: 80.61% | Support 10/25/12 | | |
| 328 | Project 2007-09 | Successive Ballot | 10/19/2012 | 10/31/2012 | Quorum: 75.95% Approve: 75.95% | | | |
| 329 | Project 2007-09 | Successive Ballot | 10/19/2012 | 10/31/2012 | Quorum: 75.00% Approve: 75.00% | | | |
| 330 | Project 2007-09 | Successive Ballot | 10/19/2012 | 10/31/2012 | Quorum: 69.21% Approve: 58.41% | | | |
| 331 | Project 2007-09 | Successive Ballot | 10/19/2012 | 10/31/2012 | Quorum: 72.34% Approve: 72.34% | | | |
| 332 | Project 2007-09 | Successive Ballot | 10/19/2012 | 10/31/2012 | Quorum: 60.87% Approve: 70.84% | | | |

**Link to Ballot Results:**
**http://standards.nerc.net/Ballots.aspx**
**(clicking in the column to the right of "Ballot Period" opens links to the Ballot Results)**

| Line | Project | Ballot Type | Start Date | End Date (Active Ballots Shaded) | Ballot Results | Recommendation / Date | Have NERC Voted | Comments |
|---|---|---|---|---|---|---|---|---|
| 333 | Project 2007-09 | Non-binding Poll | 10/19/2012 | 10/31/2012 | Quorum: 75.88% Approval: 75.88% | | | |
| 334 | Project 2007-09 | Non-binding Poll | 10/19/2012 | 10/31/2012 | Quorum: 75.88% Approval: 72.72% | | | |
| 335 | Project 2007-09 | Non-binding Poll | 10/19/2012 | 10/31/2012 | Quorum: 75.88% Approval: 62.63% | | | |
| 336 | Project 2007-09 | Non-binding Poll | 10/19/2012 | 10/31/2012 | Quorum: 74.86% Approval: 74.86% | | | |
| 337 | Project 2007-09 | Non-binding Poll | 10/19/2012 | 10/31/2012 | Quorum: 70.51% Approval: 65.66% | | | |
| 338 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 95.34% | Support 10/26/12 | | |
| 339 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.81% Approval: 95.51% | Support 10/26/12 | | |
| 340 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.81% Approval: 89.79% | Support 10/26/12 | | |
| 341 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 95.34% | Support 10/26/12 | | |
| 342 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 95.51% | Support 10/26/12 | | |
| 343 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 89.79% | Support 10/26/12 | | |
| 344 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 95.47% | Support 10/26/12 | | |
| 345 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 94.60% | Support 10/26/12 | | |
| 346 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 89.79% | Support 10/26/12 | | |
| 347 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.84% Approval: 95.61% | Support 10/26/12 | | |
| 348 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 85.81% Approval: 94.91% | Support 10/26/12 | | |
| 349 | Project 2008-06 | Recirculation Ballot | 10/26/2012 | 11/25/2012 | Quorum: 82.67% Approval: 89.79% | Support 10/26/12 | | |
| 350 | Project 2009-01 | Recirculation Ballot | 10/24/2012 | 11/23/2012 | Quorum: 85.14% Approval: 71.28% | | | |
| 351 | Project 2009-01 | Non-binding Poll | 10/24/2012 | 11/23/2012 | Quorum: 78.83% Approval: 71.28% | | | |
| 352 | Project 2007-12 | Successive Ballot | 10/26/2012 | 11/26/2012 | Quorum: 92.28% Approval: 76.84% | Support 11/26/12 | | |
| 353 | Project 2010-11 | Initial Ballot | 11/8/2012 | 11/19/2012 | Quorum: 88.21% Approval: 88.21% | | | |
| 354 | Project 2012-INT-02 | Initial Ballot | 11/8/2012 | 11/19/2012 | Quorum: 84.81% Approval: 72.57% | Oppose 11/19/12 | | |
| 355 | Project 2013-02 | Initial Ballot | 11/30/2012 | 12/10/2012 | Quorum: 84.21% Approval: 90.41% | Support 12/10/12 | | |
| 356 | Project 2007-02 | Successive Ballot | 11/28/2012 | 12/13/2012 | Quorum: 76.78% Approval: 77.17% | No Consensus 12/13/12 | | |
| 357 | Project 2007-02 | Non-binding Poll | 11/28/2012 | 12/13/2012 | Quorum: 77.21% Approval: 57.41% | | | |
| 358 | Project 2007-06 | Successive Ballot | 12/7/2012 | 12/17/2012 | Quorum: 83.41% Approval: 65.21% | Oppose 12/17/12 | | |
| 359 | Project 2007-06 | Non-binding Poll | 12/7/2012 | 12/17/2012 | Quorum: 75.04% Approval: 60.21% | | | |
| 360 | Project 2012-INT-05 | Initial Ballot | 12/11/2012 | 12/20/2012 | Quorum: 80.26% Approval: 95.60% | Support 12/13/12 | | |
| 361 | blnk (blnk) | Successive Ballot | 12/12/2012 | 12/20/2012 | Quorum: 82.84% Approval: 82.84% | Support 12/20/12 | | |
| 362 | Project 2007-09 | Recirculation Ballot | 12/12/2012 | 12/21/2012 | Quorum: 90.89% Approval: 72.06% | | | |
| 363 | Project 2007-09 | Recirculation Ballot | 12/12/2012 | 12/21/2012 | Quorum: 90.89% Approval: 78.39% | | | |
| 364 | Project 2007-09 | Recirculation Ballot | 12/12/2012 | 12/21/2012 | Quorum: 90.89% Approval: 72.27% | | | |
| 365 | Project 2007-09 | Recirculation Ballot | 12/12/2012 | 12/21/2012 | Quorum: 90.89% Approval: 73.61% | | | |
| 366 | Project 2007-12 | Recirculation Ballot | 12/12/2012 | 12/21/2012 | Quorum: 86.19% Approval: 76.84% | | | |
| 367 | Project 2007-09 | Successive Ballot | 1/2/2013 | 1/11/2013 | Quorum: 78.40% Approval: 60.31% | Support 1/11/13 | | |
| 368 | Project 2007-09 | Non-binding Poll | 1/2/2013 | 1/11/2013 | Quorum: 78.40% Approval: 55.68% | | | |
| 369 | Project 2010-11 | Successive Ballot | 1/2/2013 | 1/11/2013 | Quorum: 89.47% Approval: 89.47% | No Consensus 1/11/13 | | |
| 370 | Project 2010-14.1 | Initial Ballot | 1/4/2013 | 1/14/2013 | Quorum: 87.94% Approval: 72.46% | Support 1/11/13 | | |
| 371 | Project 2010-14.1 | Non-binding Poll | 1/4/2013 | 1/14/2013 | Quorum: 87.94% Approval: 57.17% | | | |
| 372 | Project 2013-02 | Recirculation Ballot | 1/8/2013 | 1/17/2013 | Quorum: 84.46% Approval: 89.21% | Support 1/17/13 | | |
| 373 | Project 2012-INT-05 | Recirculation Ballot | 1/14/2013 | 1/23/2013 | Quorum: 80.09% Approval: 98.09% | Support 1/23/13 | | |
| 374 | blnk (blnk) | Recirculation Ballot | 1/14/2013 | 1/24/2013 | Quorum: 82.86% Approval: 97.14% | Support 1/24/13 | | |
| 375 | Project 2010-11 | Recirculation Ballot | 1/22/2013 | 1/31/2013 | Quorum: 88.01% Approval: 88.01% | No Consensus 1/31/13 | | |
| 376 | Project 2012-INT-02 | Recirculation Ballot | 1/22/2013 | 1/31/2013 | Quorum: 83.67% Approval: 72.57% | Oppose 1/31/13 | | |
| 377 | Project 2010-01.1 | Successive Ballot | 2/1/2013 | 2/10/2013 | Quorum: 77.62% Approval: 70.06% | Support 2/5/13 | | |
| 378 | Project 2010-01.1 | Non-binding Poll | 2/1/2013 | 2/10/2013 | Quorum: 77.62% Approval: 63.60% | | | |
| 379 | Project 2007-09 | Successive Ballot | 2/15/2013 | 2/28/2013 | Quorum: 79.80% Approval: 61.31% | Support 2/21/13 | | |
| 380 | Project 2007-09 | Non-binding Poll | 2/15/2013 | 2/28/2013 | Quorum: 79.80% Approval: 56.24% | | | |
| 381 | Project 2010-13.2 | Initial Ballot | 3/1/2013 | 3/11/2013 | Quorum: 74.81% Approval: 74.81% | | | |
| 382 | Project 2012-08.1 | Successive Ballot | 3/1/2013 | 3/11/2013 | Quorum: 77.48% Approval: 84.27% | No Consensus 3/11/13 | | NPCC to abstain - international referral of the DSC and BPS is not cost-it-helpfully beneficial |
| 383 | Project 2012-INT-04 | Initial Ballot | 3/5/2013 | 3/14/2013 | Quorum: 83.94% Approval: 97.18% | Support 3/14/13 | | |
| 384 | Project 2012-INT-06 | Initial Ballot | 3/5/2013 | 3/15/2013 | Quorum: 80.51% Approval: 97.17% | Support 3/15/13 | | |
| 385 | Project 2007-09 | Recirculation Ballot | 3/18/2013 | 3/27/2013 | Quorum: 81.23% Approval: 89.81% | Support 3/27/13 | | |
| 386 | Project 2007-02 | Successive Ballot | 3/27/2013 | 4/5/2013 | Quorum: 79.39% Approval: 57.50% | No Consensus 4/5/13 | | The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard with some caveats and details. Comments have received were necessary and that existing antecedents already for road is sufficient. Recognition of the NERC NOT's expectations that COID-19? will be approved by the Board of Trustees and that then the approval NPCC has some affirmatively and will support the standard, including our concerns. |
| 387 | Project 2007-02 | Non-binding Poll | 3/27/2013 | 4/5/2013 | Quorum: 77.97% Approval: 47.50% | | | |
| 388 | Project 2010-14.1 | Initial Ballot | 4/16/2013 | 4/25/2013 | Quorum: 88.60% Approval: 66.98% | No Consensus 4/25/13 | | The majority of NPCC's Balancing Authorities have indicated that they have conducted, however NPCC as the Regional Entity has concerns with the quality of the Study that was conducted. They Field trials have indicated that there will be a significant number of DL violations as well as potential for increased ALR actuations. Coordination with the proposed Beta, Gamma, based on frequency triggers. To the extent that Generators and the NERC Beta who will have to implement this new requirement, NPCC as the Regional Entity will not an dissention. |
| 389 | Project 2010-14.1 | Initial Ballot | 4/16/2013 | 4/25/2013 | Quorum: 84.11% Approval: 42.71% | Oppose 4/25/13 | | There a lack of technical justification for the 500 MW threshold. Without it NPCC will submit suggested improvements. |
| 390 | Project 2010-14.1 | Initial Ballot | 4/16/2013 | 4/25/2013 | Quorum: 89.21% Approval: 23.84% | Oppose 4/25/13 | | Lacuna of large blocks of load are typically owned by consolidated transmission owners. Without technical and conditioned adjustments made to generation in order to bring the Gamma Trigger down and further transmission issues NPCC will submit suggested improvements. |
| 391 | Project 2010-14.1 | Project 2010-14.2 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: Bnk-001-2 | Non-binding Poll | 4/16/2013 | 4/25/2013 | Quorum: % Approval: % | | |
| 392 | Project 2010-14.1 | Project 2010-14.2 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: Bnk-001-2 | Non-binding Poll | 4/16/2013 | 4/25/2013 | Quorum: % Approval: % | | |
| 393 | Project 2010-14.1 | Project 2010-14.2 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: Bnk-001-2 | Non-binding Poll | 4/16/2013 | 4/25/2013 | Quorum: % Approval: % | | |
| 394 | Project 2012-08.1 | Project 2012-08.2 - Phase 2 of Glossary Update: Statutory Definitions | Recirculation Ballot | 4/16/2013 | 4/25/2013 | Quorum: 88.75% Approval: 88.21% | No Consensus 5/13/13 | |
| 395 | Project 2010-13.2 | Project 2010-13.2 Phase 1 of Relay Loadability: Generators | Successive Ballot | 5/15/2013 | 5/24/2013 | Quorum: 81.25% Approval: 69.22% | Support 5/23/13 | The Regional Standard Development Team indicated any concerns of significance that would warrant a ballot to the standard, and the requirements a yes vote, "affirmative", to accept the standard |
| 396 | Project 2010-13.2 | Project 2010-13.2 Phase 1 of Relay Loadability: Generators | Non-binding Poll | 5/15/2013 | 5/24/2013 | Quorum: 80.17% Approval: 61.11% | | |
| 397 | Project 2007-06 | Successive Ballot | 5/16/2013 | 5/26/2013 | Quorum: 77.11% Approval: 72.71% | | | |
| 398 | Project 2007-06 | Non-binding Poll | 5/16/2013 | 5/26/2013 | Quorum: 77.11% Approval: 57.71% | | | |
| 399 | Project 2010-17 | Initial Ballot | 7/8/2013 | 7/12/2013 | Quorum: 83.93% Approval: 83.79% | | | |
| 400 | Project 2007-02 | Successive Ballot | 7/15/2013 | 7/24/2013 | Quorum: 79.32% Approval: 58.26% | No Consensus 7/24/13 (Due to the concerns raised over the potential actions by the NERC BOT and FERC as well as the Regional Entity enforcement 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 have raised a serious concern that in order to measure compliance with TO, TOP, and GO, the Transmission of Reliability Directives to be investigated to determine if RC communication protocols and communication protocols have been violated. Also if was determined that the communication protocols would have to approved by the Regional Entities and the legal issues if protocols aren't approved and rarely question on the validity of the protocols. NPCC will be submitting some helpful comments on the proposed pass and some non-substantive revisions (as performed prior to the ballot) and support the NERC Project team. |
| 401 | Project 2007-02 | Non-binding Poll | 7/15/2013 | 7/24/2013 | Quorum: 79.20% Approval: 47.26% | | | |
| 402 | Project 2010-13.2 | Successive Ballot | 7/15/2013 | 7/24/2013 | Quorum: 83.81% Approval: 72.43% | Support 7/24/13 | | |
| 403 | Project 2010-13.2 | Non-binding Poll | 7/15/2013 | 7/24/2013 | Quorum: 83.81% Approval: 64.63% | | | |
| 404 | Project 2010-14.1 | Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: Bnk-001-2 | Final Ballot | 7/16/2013 | 7/25/2013 | Quorum: 92.21% Approval: 74.24% | No Consensus 7/25/13 | The RSC has not reached a full consensus however the majority are in support. Issues remaining for the RSC are in support are concern over "Firing Ante" more frequently and the potential for units to 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: Generators - PRC-023-3 | Initial Ballot | 7/26/2013 | 8/5/2013 | Quorum: 80.05% Approval: 83.60% | Support 8/5/13 | |
| 406 | Project 2010-13.2 | Project 2010-13.2 - Phase 2 of Relay Loadability: Generators - PRC-023-3 | Final Ballot | 8/21/2013 | 8/31/2013 | Quorum: 89.11% Approval: 87.11% | Support 8/31/13 | |
| 406 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1 | Initial Ballot | 8/22/2013 | 9/11/2013 | Quorum: 75.31% Approval: 62.74% | Support 9/11/13 | |
| 407 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1 | Non-binding Poll | 8/22/2013 | 9/11/2013 | Quorum: 75.31% Approval: 55.46% | | |
| 408 | 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: 76.81% Approval: 77.81% | 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: 77.81% Approval: 61.67% | | |
| 411 | Project 2012-05 | Project 2012-05 ATC Revisions (MOD-N) - MOD-001-2 | Ballot | 9/24/2013 | 10/3/2013 | Quorum: 71.14% Approval: 71.14% | No Consensus 9/24/13 | NPCC to support with comments |
| 412 | Project 2012-05 | Project 2012-05 ATC Revisions (MOD-N) - MOD-001-2 | Non-binding Poll | 9/24/2013 | 10/3/2013 | Quorum: 71.08% Approval: 52.35% | | |
| 413 | Project 2010-01 | Project 2010-01 - Training - PER-005-2 | Ballot | 9/25/2013 | 9/5/2013 | Quorum: 75.35% Approval: 24.66% | No Consensus 9/5/13 | NPCC to support with comments. The most contentious issues raised by RSC members was concerns over the proposed definition and the potential to easily expand those meeting the definition of Operations and Compliance and that there was no need for a standard, that the issue of training should be addressed through other means. |
| 414 | Project 2010-01 | Project 2010-01 - Training - PER-005-2 | Non-binding Poll | 9/25/2013 | 9/5/2013 | Quorum: 60.41% Approval: 24.24% | | |
| 415 | Project 2013-04 | Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3 | Ballot | 9/25/2013 | 9/5/2013 | Quorum: 81.89% Approval: 43.79% | Oppose 9/5/13 | The constant, in the view of the phrase "or operator manual" including but not limited to... applicability issues, both same as the issues raised in the 2007 other substantive issues. NPCC will be submitting detailed comments on the other issues. The RSC does not believe it would be beneficial to have a "yes" vote, or a "yes" point in the red copy, if it has the initial ballot, would still be voting affirmative and would be moving to reconsideration due to the substantive changes that would be made. In the interim NPCC will be submitting helpful comments to NERC and continue to be everything team effort. |
| 416 | Project 2013-04 | Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3 | Non-binding Poll | 9/25/2013 | 9/5/2013 | Quorum: 79.91% Approval: 43.79% | | |
| 417 | Project 2010-03 | Project 2010-03 - Modeling Data (MOD-26, -MOD-027) - MOD-033-1, MOD-034-0,1 | Ballot | 9/26/2013 | 9/6/2013 | Quorum: 82.24% Approval: 41.24% | Support 9/5/13 | |
| 418 | Project 2010-03 | Project 2010-03 - Modeling Data (MOD-26, -MOD-027) - MOD-033-1, MOD-034-0,1 | Non-binding Poll | 9/26/2013 | 9/6/2013 | Quorum: 82.24% Approval: 40.60% | | |
| 419 | Project 2010-04 | Project 2010-04 - Demand Data (MOD-C) - MOD-031-1 | Ballot | 9/26/2013 | 9/6/2013 | Quorum: 81.96% Approval: 58.11% | Support 9/5/13 | |
| 420 | Project 2010-04 | Project 2010-04 - Demand Data (MOD-C) - MOD-031-1 | Non-binding Poll | 9/26/2013 | 9/6/2013 | Quorum: 81.96% Approval: 58.97% | | |
| 421 | Project 2010-17 | Project 2010-17 - Definition of Bulk Electric System (Phase 2) | Additional Ballot | 10/8/2013 | 10/8/2013 | Quorum: 79.84% Approval: 58.11% | Support 9/5/13 | |
| 424 | Project 2010-13.2 | Project 2010-13.2 - Phase 2 of Relay Loadability: Generators - PRC-023-3 | Final Ballot | 10/8/2013 | 10/13/2013 | Quorum: 83.85% 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 - Bnk-001-2, Bnk-1011-1 | Ballot | 9/8/2013 | 9/16/2013 | Quorum: 76.21% Approval: 76.21% | No Consensus 9/16/13 | |
| 423 | Project 2010-14.1 | Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - Bnk-001-2, Bnk-1011-1 | Non-binding Poll | 9/8/2013 | 9/16/2013 | Quorum: 76.21% Approval: 52.84% | | |
| 424 | Project 2012-INT-04 | Project 2012-INT-04 - Interpretation of CIP-007-3 for TFE | Final Ballot | 9/11/2013 | 9/20/2013 | Quorum: 90.88% Approval: 88.01% | Support 3/14/13 | |
| 425 | Project 2012-INT-06 | Project 2012-INT-06 - Interpretation of CIP-005-3 for Consumers Energy | Final Ballot | 9/11/2013 | 9/20/2013 | Quorum: 90.88% Approval: 97.17% | Support 3/15/13 | |
| 427 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1 | Additional Ballot | 10/8/2013 | 10/17/2013 | Quorum: 77.28% Approval: 68.71% | Support 10/10/13 | |
| 428 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1 | Non-binding Poll | 10/8/2013 | 10/17/2013 | Quorum: 77.28% Approval: 50.04% | | |

**List to Ballot Results**
**http://standards.nerc.net/Ballots.aspx**
**(clicking in the column to the left of "Ballot Period" opens links to the Ballot Results)**

| Line | Project | Ballot Type | Start Date | End Date (Actual Closed At Midnight) | Ballot Results | Recommendation / Date | Have NERC Voted | Comments |
|---|---|---|---|---|---|---|---|---|
| 429 | Project 2007-17.2 | Final Ballot | 04/04/2013 | 04/05/2013 | Quorum: 85.71% Approval: 75.00% | | | |
| 430 | Project 2010-17 | Additional Ballot | 04/04/2013 | 04/04/2013 | Quorum: 75.81% Approval: 72.93% | Support 10/21/13 | | |
| 431 | Project 2013-03 | Final Ballot | 04/05/2013 | 05/04/2013 | Quorum: 76.67% Approval: 82.87% | | | |
| 432 | Project 2007-02 | Additional Ballot | 04/05/2013 | 05/7/2013 | Quorum: 76.67% Approval: 82.87% | No Consensus 11/13/13 | | |
| 433 | Project 2010-01 - Training - FAC-003-2 | Additional Ballot | 5/1/2013 | 5/10/2013 | Quorum: 75.21% Approval: 68.48% | Support 11/13/13 | | |
| 434 | Project 2008-12 | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.42% Approval: 67.41% | Support 11/13/13 | | |
| 435 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - INT-004-3 | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.42% Approval: 67.41% | Support 11/13/13 | | |
| 436 | Project 2008-12 | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.42% Approval: 68.49% | Support 11/13/13 | | |
| 437 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - INT-005-4 | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.42% Approval: 68.41% | Support 11/13/13 | | |
| 438 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - INT-006-4 | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.21% Approval: 67.41% | Support 11/13/13 | | |
| 439 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - Definition | Initial Ballot | 5/1/2013 | 05/13/2013 | Quorum: 75.42% Approval: 77.87% | Support 11/13/13 | | |
| 440 | Project 2010-17 - Definition of Bulk Electric System (Phase 2) | Final Ballot | 5/1/2013 | 05/10/2013 | Quorum: 75.21% Approval: 72.84% | Support 10/21/13 | | |
| 441 | Project 2012-05 | Additional Ballot | 5/1/2013 | 05/20/2013 | Quorum: 81.69% Approval: 75.00% | No Consensus 11/13/13 | | |
| 442 | Project 2010-03 - Modeling Data (MOD-B) - MOD-031-1 | Additional Ballot | 5/1/2013 | 05/09/2013 | Quorum: 70.81% Approval: 73.46% | Support 8/15/13 | | |
| 443 | Project 2010-03 | Additional Ballot | 5/1/2013 | 05/09/2013 | Quorum: 70.81% Approval: 73.46% | Support 8/15/13 | | |
| 444 | Project 2010-04 - Demand Data (MOD-C) - MOD-032-1 | Additional Ballot | 5/1/2013 | 05/13/2013 | Quorum: 69.64% Approval: 80.21% | Support 8/15/13 | | |
| 445 | Project 2013-04 | Additional Ballot | 5/1/2013 | 05/05/2013 | Quorum: 80.81% Approval: 69.14% | | | |
| 446 | Project 2013-04 | Additional Ballot | 5/15/2013 | 05/25/2013 | Quorum: 80.81% Approval: 69.14% | | | |
| 447 | Project 2010-14.1 | Additional Ballot | 5/22/2013 | 05/31/2013 | Quorum: 75.29% Approval: 84.54% | No Consensus 11/13/13 | Affirmative | |
| 448 | Project 2007-11 | Initial Ballot | 5/28/2013 | 06/7/2013 | Quorum: 82.25% Approval: 62.25% | No Consensus 12/03/13 | Affirmative | Highlights of comments received opposed:<br><br>1 Agreement with the Interpretation of Requirement (R5) Studies for which data that is derivative<br>2 Clarification needed for some terms in the standard<br>3 Editorial suggestions |
| 449 | Project 2010-03 | Final Ballot | 5/28/2013 | 06/06/2013 | Quorum: 87.53% Approval: 81.71% | Support 8/15/13 | Affirmative | |
| 450 | Project 2008-12 | Final Ballot | 5/30/2013 | 06/09/2013 | Quorum: 85.87% Approval: 80.77% | Support 11/13/13 | Affirmative | |
| 451 | Project 2008-12 | Final Ballot | 5/30/2013 | 06/09/2013 | Quorum: 85.87% Approval: 81.68% | Support 11/13/13 | Affirmative | |
| 452 | Project 2008-12 | Final Ballot | 5/30/2013 | 06/09/2013 | Quorum: 84.78% Approval: 81.71% | Support 11/13/13 | Affirmative | |
| 453 | Project 2012-05 | Final Ballot | 05/31/2013 | 06/10/2013 | Quorum: 87.21% Approval: 86.48% | No Consensus 8/26/13 | Affirmative | |
| 454 | Project 2013-04 | Final Ballot | 5/31/2013 | 06/10/2013 | Quorum: 81.61% Approval: 91.61% | | Affirmative | |
| 455 | Project 2007-06 - System Protection Coordination - PRC-027-1 | Additional Ballot | 6/6/2013 | 06/15/2013 | Quorum: 79.86% Approval: 77.14% | No Consensus 11/13/13 | Affirmative | |
| 456 | Project 2010-03 - Modeling Data (MOD-B) - MOD-033-1 | Additional Ballot | 7/03/2014 | 07/13/2014 | Quorum: 75.61% Approval: 81.41% | Support 8/15/13 | Affirmative | |
| 457 | Project 2010-01 - Training - FAC-003-2 | Additional Ballot | 7/8/2014 | 7/21/2014 | Quorum: 74.81% Approval: 74.81% | Support 11/13/13 | Affirmative | |
| 458 | Project 2008-12 | Initial Ballot | 7/10/2014 | 7/21/2014 | Quorum: 75.21% Approval: 77.87% | Support 11/13/13 | Affirmative | |
| 459 | Project 2008-12 | Initial Ballot | 7/10/2014 | 7/21/2014 | Quorum: 75.21% Approval: 78.23% | Support 11/13/13 | Affirmative | |
| 460 | Project 2008-12 | Initial Ballot | 7/10/2014 | 7/21/2014 | Quorum: 75.21% Approval: 81.17% | Support 11/13/13 | Affirmative | |
| 461 | Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4 | Additional Ballot | 12/1/2014 | 12/11/2014 | Quorum: 79.01% Approval: 84.21% | No Consensus 3/24/14 | Affirmative | Ballot Period Extended to 12/11/14 |
| 462 | Project 2008-12 | Final Ballot | 12/1/2014 | 12/10/2014 | Quorum: 83.88% Approval: 83.44% | Support 11/13/13 | Affirmative | |
| 463 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - INT-003-4 | Final Ballot | 12/1/2014 | 12/10/2014 | Quorum: 83.88% Approval: 83.41% | Support 11/13/13 | Affirmative | |
| 464 | Project 2010-03 - Modeling Data (MOD-B) - MOD-033-1 | Final Ballot | 12/1/2014 | 12/10/2014 | Quorum: 82.41% Approval: 84.21% | Support 8/15/13 | Affirmative | |
| 465 | Project 2010-01 - Training - FAC-003-2 | Final Ballot | 12/1/2014 | 12/10/2014 | Quorum: 83.81% Approval: 77.87% | Support 11/13/13 | Affirmative | |
| 466 | Project 2008-12 - Coordinate Interchange Standards - Various IRT standards - Definition | Final Ballot | 12/1/2014 | 12/10/2014 | Quorum: 83.21% Approval: 80.21% | Support 11/13/13 | Affirmative | |
| 467 | Project 2010-05.1 - Protection Systems (Phase 1 Misoperations) - PRC-004-3 | Additional Ballot | 12/1/2014 | 12/10/2014 | Quorum: 75.06% Approval: 77.14% | Support 6/5/14 | Affirmative | Ballot Period Extended to 12/11/14 |
| 468 | Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4 | Final Ballot | 12/08/2014 | 4/7/2014 | Quorum: 79.21% Approval: 72.21% | Support 3/24/14 | Affirmative | |
| 469 | Project 2010-03 - Demand Data (MOD-C) - MOD-033-1 | Additional Ballot | 4/1/2014 | 4/10/2014 | Quorum: 79.61% Approval: 83.61% | Support 8/15/13 | Affirmative | |
| 470 | Project 2013-04 - Voltage and Reactive Control - VAR-001-5 | Additional Ballot | 4/4/2014 | 4/14/2014 | Quorum: 79.61% Approval: 77.61% | -- | -- | |
| 471 | Project 2014-04 | Initial Ballot | 4/28/2014 | 4/24/2014 | Quorum: 85.87% Approval: 85.87% | Support 4/25/14 | Abstain | |
| 472 | Project 2010-03 | Final Ballot | 4/28/2014 | 5/1/14 | Quorum: 85.87% Approval: 85.87% | Support =4/30/14 | Affirmative | |
| 473 | Project 2013-04 | Final Ballot | 4/28/2014 | 5/1/14 | Quorum: 85.84% Approval: 85.84% | Support =4/30/14 | Affirmative | |
| 474 | Project 2014-04 | Final Ballot | 5/1/2014 | 5/5/2014 | Quorum: 85.21% Approval: 85.21% | Support -4/25/14 | Abstain | |
| 475 | Project 2010-02 | Initial Ballot | 5/8/2014 | 5/15/2014 | Quorum: 81.79% Approval: 81.79% | No Consensus -5/15/14 | Reject | |
| 476 | Project 2010-02 - Connecting Certain Generating Facilities - PRC-005-2 and PRC-002-2 | Initial Ballot | 5/8/2014 | 5/15/2014 | Quorum: 81.79% Approval: 81.79% | | | |
| 476 | Project 2012-13 - NUC - Nuclear Plant Interface Coordination | Initial Ballot | 5/13/2014 | 5/22/2014 | Quorum: 80.65% Approval: 87.66% | Support -5/20/14 | Affirmative | |
| 477 | Project 2007-17.3 | Initial Ballot | 5/15/2014 | 5/23/2014 | Quorum: 82.21% Approval: 87.21% | Support | Affirmative | |
| 478 | Project 2010-13.3 | Initial Ballot | 5/30/2014 | 6/8/2014 | Quorum: 75.06% Approval: 77.14% | Cons. no Support -6/8/14 | Negative | |
| 479 | Project 2010-02 | Final Ballot | 6/12/2014 | 6/23/2014 | Quorum: 85.87% Approval: 85.87% | Support | Affirmative | |
| 479 | Project 2010-02 - Connecting Certain Generating Facilities - PRC-005-2 and PRC-002-2 | Additional Ballot | 6/12/2014 | 6/22/2014 | Quorum: 85.87% Approval: 85.87% | Support | Affirmative | Extended to achieve a quorum. |
| 480 | Project 2010-05.1 - Protection Systems (Phase 1 Misoperations) - PRC-004 | Additional Ballot | 6/26/2014 | 7/8/2014 | Quorum: 79.21% Approval: 77.21% | Support | Affirmative | Extended to achieve a quorum. |
| 481 | Project 2014-03 | Ballot | 6/23/2014 | 7/2/2014 | Quorum: 83.21% Approval: 78.21%<br><br>Segment:<br>R1 (1NAY,13NAY,1NV)<br>R3 (6NAY,1FNAY,1E)<br>R4 (1NAY,1FNAY,1E)<br>R5 (5NAY,1FNAY,1A)<br>R6 (4NAY,1FNAY,1A)<br>Segment:<br>M1 (7NAY,1FNAY,1E)<br>M3 (7NAY,1FNAY,1E)<br>M4 (1NAY,1FNAY,1E)<br>M5 (7NAY,1FNAY,1E)<br>M6 (4NAY,1FNAY,1A) | No Consensus -6/24/14 | Affirmative<br>Negative<br>Negative<br>Affirmative<br>Affirmative<br>Affirmative<br>Negative<br>Affirmative<br>Affirmative | |
| 482 | Project 2012-13 | Final Ballot | 6/26/2014 | 7/6/2014 | Quorum: 80.81% Approval: 87.14% | Support -6/25/14 | Affirmative | |
| 483 | Project 2014-02<br><br>Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions<br>Roll-Call Ballot<br>http://standards.nerc.net/BallotResults.aspx | Final Ballot | 7/7/2014 | 7/16/2014 | Quorum: 85.21% Approval: 77.21%<br><br>Segment:<br>R1 (7NAY,4NAY,1E)<br>R3 (1NAY,1NAY,1E)<br>R4 (1NAY,1NAY,1E)<br>R5 (6NAY,1NAY,1E)<br>R6 (4NAY,1NAY,1A)<br>Segment:<br>M1 (7NAY,1NAY,1E)<br>M3 (7NAY,1NAY,1E)<br>M4 (1NAY,1NAY,1E)<br>M5 (7NAY,1NAY,1E)<br>M6 (4NAY,1NAY,1A) | CIP-002 No<br>CIP-003 No<br>CIP-004 No<br>CIP-005 No<br>CIP-006 No<br>CIP-007 No<br>CIP-008 No<br>CIP-009 No<br>Definitions No<br>Implem. Plan No | | |
| 484 | Project 2010-05.2 - Special Protection Systems (Phase 2 of Protection Systems) | Final Ballot | 7/16/2014 | 7/05/2014 | Quorum: 85.21% Approval: 77.21% | Support -7/23/14 | | |
| 485 | Project 2014-01 | Final Ballot | 7/18/2014 | 7/28/2014 | Quorum: 85.21% Approval: 78.21%<br><br>Segment:<br>R1 (6NAY,1NAY,1E)<br>R3 (5NAY,1E)<br>R4 (1NAY,1NAY,1E)<br>R5 (6NAY,1E)<br>R6 (4NAY,1A) | Affirmative -7/29/14 | Affirmative | |
| 486 | Project 2012-13 | Final Ballot | 7/21/2014 | 7/30/2014 | Quorum: 85.21% Approval: 87.21% | Affirmative -7/07/14 | | |
| 487 | Project 2012-13 | Initial Ballot | 7/29/2014 | 8/7/2014 | Quorum: 79.21% Approval: 79.21% | Affirmative -7/07/14 | | |
| 488 | Project 2012-13 | Initial Ballot | 8/6/2014 | 8/15/2014 | Quorum: 77.21% Approval: 77.21% | Negative -8/14/14 | Negative | |
| 489 | Project 2014-01 | Final Ballot | 7/29/2014 | 8/7/2014 | Quorum: 77.21% Approval: 77.21% | Support | Affirmative | |
| 490 | Project 2014-01<br><br>Project 2014-01 Standards Applicability for Dispersed Generation Resources | Final Ballot | 8/27/2014 | 9/5/2014 | Quorum: 92.20% Approval: 92.20%<br><br>Segment:<br>R1 (9NAY,1E)<br>R3 (9NAY,1E)<br>R4 (1NAY,1E)<br>R5 (9NAY,1E)<br>R6 (5NAY,1E) | Support | Affirmative | |
| 491 | Project 2007-17.3 | Additional Ballot | 9/3/2014 | 9/12/2014 | Quorum: 81.21% Approval: 78.21% | Support -9/8/14 | Affirmative | |
| 492 | Project 2014-03 | Additional Ballot | 9/12/2014 | 9/19/2014 | Quorum: 81.21% Approval: 78.21%<br><br>Segment:<br>R1 (5NAY,1NAY,1NV,1E)<br>R3 (5NAY,1FNAY,1E)<br>R4 (1NAY,1FNAY,1E)<br>R5 (6NAY,1FNAY,1E)<br>R6 (4NAY,1FNAY,1A)<br><br>Segment:<br>M1 (7NAY,1FNAY,1E)<br>M3 (7NAY,1FNAY,1E)<br>M4 (1NAY,1FNAY,1E)<br>M5 (7NAY,1FNAY,1E)<br>M6 (4NAY,1FNAY,1A) | CIP-002-5 Negative<br>CIP-003-5 Affirmative<br>CIP-004-5 Affirmative<br>CIP-005-5 Affirmative<br>CIP-006-5 Affirmative<br>CIP-007-5 Affirmative<br>CIP-008-5 Affirmative<br>CIP-009-5 Affirmative<br>RD-001-1 No consensus however the majority indicated an Affirmative<br><br>RD-002-1 Negative<br>RD-003-1 No consensus a majority indicated a Negative and the others indicated abstention<br>RD-010-1 Affirmative<br>RD-011-1 Affirmative<br>RD-012-1 Affirmative<br>Implementation Plan and Definitions Affirmative<br>5/28/14 | CIP-003-6 and CIP-010-2 Affirmative | |
| 493 | Project 2010-14.1 | Additional Ballot | 9/22/2014 | 10/2/2014 | Quorum: 79.94% Approval: 90.21% | Negative -10/5/14 | | |
| 494 | Project 2010-13.3 | Additional Ballot | 9/26/2014 | 10/6/2014 | Quorum: 79.01% Approval: 92.01% | Affirmative -10/5/14 | | |
| 495 | Project 2012-13 | Additional Ballot | 9/26/2014 | 10/6/2014 | Quorum: 79.01% Approval: 92.01%<br><br>Segment:<br>R1 (6NAY,1E)<br>R3 (5NAY,1E)<br>R4 (1NAY,1E)<br>R5 (6NAY,1E)<br>R6 (4NAY,1A) | Affirmative -10/7/14 | Affirmative | |
| 496 | Project 2012-13 | Additional Ballot | 10/3/2014 | 10/10/2014 | Quorum: 77.01% Approval: 92.01% | Affirmative -10/7/14 | | |
| 497 | Project 2010-05.2 | Additional Ballot | 10/3/2014 | 10/13/2014 | Quorum: 80.14% Approval: 79.14% | Affirmative -10/7/14 | | |
| 498 | Project 2014-01 | Final Ballot | 10/7/2014 | 10/16/2014 | Quorum: 92.01% Approval: 92.01%<br><br>Segment:<br>R1 (9NAY,1E)<br>R3 (9NAY,1E)<br>R4 (1NAY,1E)<br>R5 (9NAY,1E)<br>R6 (5NAY,1E) | Affirmative -10/14/14 | | |
| 499 | Project 2014-02 | Final Ballot | 10/8/2014 | 10/17/2014 | Quorum: 84.21% Approval: 81.21%<br><br>Segment:<br>R1 (6NAY,1NAY,1E)<br>R3 (6NAY,1FNAY,1E)<br>R4 (1NAY,1FNAY,1E)<br>R5 (6NAY,1FNAY,1E)<br>R6 (4NAY,1FNAY,1A)<br><br>Segment:<br>M1 (7NAY,1FNAY,1E)<br>M3 (7NAY,1FNAY,1E)<br>M4 (1NAY,1FNAY,1E)<br>M5 (7NAY,1FNAY,1E)<br>M6 (4NAY,1FNAY,1A) | CIP-003-6 no consensus<br>CIP-010-2 Affirmative<br>Non-Definitions Affirmative<br>Updated Definitions Affirmative<br>Implementation Plan Affirmative<br>Version 5 Retirements Affirmative<br>Non-binding polls Affirmative | CIP-003-6 and CIP-010-2 Affirmative | |
| 500 | Project 2009-03 | Additional Ballot | 10/20/2014 | 10/29/2014 | Quorum: 85.21% Approval: 78.21% | Affirmative -10/17/14 | | |
| 501 | Project 2014-03 | Initial Ballot | 10/20/2014 | 10/29/2014 | Quorum: 85.21% Approval: 78.21%<br><br>Segment:<br>R1 (7NAY,1FNAY,1E)<br>R3 (6NAY,1E)<br>R4 (1NAY,1E)<br>R5 (6NAY,1E)<br>R6 (4NAY,1A) | Affirmative -10/17/14 | | |
| 502 | Project 2014-03 | Initial Ballot | 10/20/2014 | 10/29/2014 | Quorum: 85.21% Approval: 78.21%<br><br>Segment:<br>R1 (7NAY,1FNAY,1E)<br>R3 (6NAY,1E)<br>R4 (1NAY,1E)<br>R5 (6NAY,1E)<br>R6 (4NAY,1A) | Affirmative -10/17/14 | | |
| 503 | Project 2007-11 | Final Ballot | 10/20/2014 | 10/31/2014 | Quorum: 71.28% Approval: 71.28% | Affirmative -10/17/14 | | |
| 504 | Project 2014-01 | Additional Ballot | 10/20/2014 | 10/31/2014 | Quorum: 71.28% Approval: 71.28%<br><br>Segment:<br>R1 (9NAY,1E)<br>R3 (9NAY,1E)<br>R4 (1NAY,1E)<br>R5 (9NAY,1E)<br>R6 (5NAY,1E) | Affirmative -10/20/14 | | |
| 505 | Project 2014-03 | Final Ballot | 10/20/2014 | 10/29/2014 | Quorum: 85.21% Approval: 78.21% | Affirmative -10/20/14 | | |
| 506 | Project 2014-03 | Final Ballot | 10/20/2014 | 10/29/2014 | Quorum: 85.21% Approval: 78.21% | Affirmative -10/20/14 | | |
| 507 | Project 2007-11 | Final Ballot | 10/28/2014 | 11/6/2014 | Quorum: 71.28% Approval: 71.28% | Affirmative -10/21/14 | | |
| 508 | Project 2007-11 | Final Ballot | 10/28/2014 | 11/6/2014 | Quorum: 71.28% Approval: 71.28% | Negative -10/21/14 | | |
| 509 | Project 2007-11 | Final Ballot | 10/28/2014 | 11/6/2014 | Quorum: 71.28% Approval: 71.28% | Affirmative -10/21/14 | | |
| 510 | Project 2014-01<br><br>Project 2014-01 Standards Applicability for Dispersed Generation Resources | Final Ballot | 10/28/2014 | 11/6/2014 | Quorum: 92.20% Approval: 92.20%<br><br>Segment:<br>R1 (9NAY,1ANAY,1BN)<br><br>Segment:<br>R5 (5NAY,1ANAY,1EN) | Affirmative -10/29/14 | | |
| 511 | Project 2014-03<br><br>Project 2014-03 Critical Infrastructure Protection Standards Version 5 Revisions | Final Ballot | 10/28/2014 | 11/6/2014 | Quorum: 85.21% Approval: 78.21%<br><br>Segment:<br>R1 (6NAY,1FNAY,1EN)<br>R3 (5NAY,1FNAY,1EN)<br>R4 (1NAY,1EN)<br>R5 (6NAY,1FNAY,1EN)<br>R6 (4NAY,1FNAY,1EN)<br><br>Segment:<br>M1 (7NAY,1FNAY,1EN)<br>M3 (7NAY,1FNAY,1EN)<br>M4 (1NAY,1FNAY,1EN)<br>M5 (7NAY,1FNAY,1EN)<br>M6 (4NAY,1FNAY,1EN) | CIP-003-6 no consensus<br>CIP-010-2 Affirmative<br>Non-Definitions Affirmative<br>Updated Definitions Affirmative<br>Implementation Plan Affirmative<br>Version 5 Retirements Affirmative<br>Non-binding polls Affirmative | CIP-003-6 and CIP-010-2 Affirmative | |
| 512 | Project 2014-03 | 2014-03 - Revisions to TOP-001 Reliability Standards | Additional Ballot | 11/6/2014 | 11/16/2014 | Quorum: 78.86% Approval: 78.86% | Affirmative -11/6/14 | |
| 513 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation | Additional Ballot | 11/12/2014 | 11/21/2014 | Quorum: 77.41% Approval: 77.41% | Affirmative -11/21/14 | |
| 514 | Project 2014-03 | Project 2010-13.2 Phase 2 of Relay Loadability: Static Power Ratings | Additional Ballot | 11/14/2014 | 11/24/2014 | Quorum: 79.41% Approval: 79.41% | Affirmative -11/21/14 | |
| 515 | Project 2013-03 | Project 2013-03 Geomagnetic Disturbance Mitigation | Final Ballot | 11/21/2014 | 11/30/2014 | Quorum: 85.21% Approval: 85.21% | Affirmative -11/21/14 | |
| 516 | Project 2014-03 | Project 2010-13.2 Phase 2 of Relay Loadability: Static Power Ratings | Final Ballot | 11/21/2014 | 11/30/2014 | Quorum: 79.21% Approval: 79.21% | Affirmative -11/21/14 | |
| 517 | Project 2014-01<br><br>Project 2014-01 Standards Applicability for Dispersed Generation Resources | Initial Ballots | 12/02/2014 | 12/12/2014 | Quorum: 92.20% Approval: 92.20%<br><br>Segment:<br>R1 (9NAY,1EN)<br><br>Segment:<br>R5 (5NAY,1ANAY,1EN) | Affirmative -12/11/14 | | |
| 518 | Project 2014-03 | 2014-03 - Revisions to TOP and IRO Standards | Additional Ballot | 12/08/2014 | 1/7/2015 | Quorum: 85.21% Approval: 85.21% | Affirmative -1/6/15 | |
| 519 | Project 2014-02<br><br>Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions | Additional Ballot | 12/08/2014 | 1/8/2015 | Quorum: 85.21% Approval: 77.21%<br><br>Segment:<br>R1 (5NAY,1NAY,1ANAY,1EN)<br>R3 (5NAY,1FNAY,1EN)<br>R4 (1NAY,1EN)<br>R5 (6NAY,1FNAY,1EN)<br>R6 (4NAY,1FNAY,1EN)<br><br>Segment:<br>M1 (7NAY,1FNAY,1EN)<br>M3 (7NAY,1FNAY,1EN)<br>M4 (1NAY,1FNAY,1EN)<br>M5 (7NAY,1FNAY,1EN)<br>M6 (4NAY,1FNAY,1EN) | CIP-003-7 Binding and non-binding polls no consensus<br>CIP-003-7 Definition Affirmative<br>CIP-003-7 Binding and non-binding polls - affirmative<br>CIP-010-2 Definition Affirmative<br>CIP-010-2 Binding and non-binding polls - affirmative<br>CIP-011-1 Binding and non-binding polls - affirmative<br>CIP-011-1 Binding and non-binding polls - affirmative<br>CIP Implementation Plan Affirmative<br>5/8/2015 | | |
| 520 | Project 2014-03 | 2014-03 - Revisions to TOP and IRO Standards - TOP-001-3 | Additional Ballots | 12/15/2014 | 1/14/2015 | Quorum: 85.21% Approval: 77.21% | Affirmative -1/6/15 | |
| 521 | Project 2014-01 | 2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3 | Initial Ballots | 12/22/2014 | 1/21/2015 | Quorum: 92.20% Approval: 92.20% | Affirmative -1/21/15 | |
| 522 | Project 2014-01 | 2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3, PRC-005-4, and PRC-005-5 | Final Ballots | 12/22/2014 | 1/21/2015 | Quorum: 92.20% Approval: 92.20%<br><br>Segment:<br>R1 (7NAY,1NAY,1EN)<br><br>Segment:<br>R5 (5NAY,1ANAY,1EN) | Affirmative -1/22/15 | | |
| 523 | Project 2014-02 | 2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-006-7, CIP-007-7, CIP-009-7, and CIP-011-2 | Final Ballot | 12/22/2014 | 1/21/2015 | Quorum: 84.21% Approval: 77.21%<br><br>Segment:<br>R1 (5NAY,1FNAY,1EN)<br>R3 (5NAY,1FNAY,1E)<br>R4 (1NAY,1EN)<br>R5 (6NAY,1FNAY,1EN)<br>R6 (4NAY,1FNAY,1EN)<br><br>Segment:<br>M1 (7NAY,1FNAY,1EN)<br>M3 (7NAY,1FNAY,1EN)<br>M4 (1NAY,1FNAY,1EN)<br>M5 (7NAY,1FNAY,1EN)<br>M6 (4NAY,1FNAY,1EN) | Affirmative -1/29/15 | | |
| 524 | Project 2014-01 | 2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-3 | Final Ballot | 1/5/2015 | 1/15/2015 | Quorum: 85.21% Approval: 78.21% | Affirmative -1/21/15 | |
| 525 | Project 2010-14.1 | Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves | Additional Ballot | 1/8/2015 | 1/18/2015 | Quorum: 79.21% Approval: 82.21% | Negative -1/13/15 | |
| 526 | Project 2008-02.2 | Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS) Misoperations | Initial Ballot | 1/27/2015 | 2/7/2015 | Quorum: 75.21% Approval: 77.21% | Affirmative -2/5/15 | |
| 527 | Project 2014-04 | Project 2014-04 Physical Security | Initial Ballot | 2/5/2015 | 2/15/2015 | Quorum: 85.21% Approval: 85.21% | Affirmative -2/11/15 | |
| 528 | Project 2008-02.2 | Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS) Misoperations | Initial Ballot | 2/17/2015 | 2/27/2015 | Quorum: 85.21% Approval: 85.21% | Affirmative -2/25/15 | |
| 529 | Project 2014-04 | Project 2014-04 Physical Security | Final Ballot | 4/20/2015 | 4/29/2015 | Quorum: 92.20% Approval: 92.20% | Affirmative -3/5/15 | |
| 530 | Project 2007-06 | Project 2007-06 System Protection Coordination | Additional Ballot | 5/8/2015 | 5/15/2015 | Quorum: 81.74% Approval: 87.01% | Negative -5/13/15 | |
| 531 | Project 2015-08 | 2015-08 Interconnection Reliability Operations and Coordination | Initial Ballot | 6/29/2015 | 7/8/2015 | Quorum: 75.21% Approval: 77.21%<br><br>Segment:<br>R1 (9NAY,1EN) | Affirmative -7/7/15 | |
| 532 | Project 2015-04 | 2015-04 Alignment of Terms | Initial Ballot | 7/17/2015 | 7/27/2015 | Quorum: 77.74% Approval: 77.74%<br><br>Segment:<br>R1 (5NAY,1FNAY,1EN)<br>R3 (5NAY,1FNAY,1E)<br>M1 (7NAY,1FNAY,1E)<br>M3 (7NAY,1FNAY,1E)<br>M4 (1NAY,1FNAY,1E)<br>M5 (7NAY,1FNAY,1E)<br>M6 (4NAY,1FNAY,1A) | Affirmative -7/27/15 | | |

| Line | Project | List to Ballot Results<br>https://standards.nerc.net/Ballots.aspx<br>(click/tap in the column to the right of "Ballot Period" opens links to the Ballot Results) | Ballot Type | Start Date | End Date<br>Current<br>Closed to Comment | Ballot Results | Recommendation / Date | Have NERC Voted | Comments |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Approval:<br>NA:10NAY7NA6.8PA<br>EU:8NAY1.5NAY.1R<br>MRO:5NAY6.8NAY1.2<br>NPCC:9NAY1.5NAY.1R<br>SERC:6NAY.8NAY<br>FI:5NAY.5NAY.1R<br>SWPA:4NAY.1NAY<br>TRE:4NAY.1NAY<br>WECC:9NAY1.5NAY<br>Negative:<br>NA:1NAY.1NAY.1A<br>MRO:1NAY.1NAY.1A<br>NPCC:1NAY.1A | | | |
| 533 | Project 2015-08 | 2015-08 Interconnection Reliability Operations and Coordination | Final Ballot | 7/21/2015 | 7/31/2015 | Quorum:<br>91.06%;90.67%%<br>Approval:<br>84.21%;84.85% | affirmative-17/1/1 | | |
| 534 | Project 2010-14.1 | Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls-Reserves | Additional Ballot | 8/11/2015 | 9/29/2015 | Quorum: 75.82%<br>Approval: 84.21% | affirmative-8/2/1/1/1 | | |
| 535 | Project 2007-06 | Project 2007-06 System Protection Coordination | Additional Ballot | 9/3/2015 | 9/11/2015 | Quorum: 85.81%<br>Approval: 91.76% | affirmative-8/0/1/1 | | |
| 536 | Project 2007-06 | Project 2007-06.2 Phase 2 of System Protection Coordination | Initial Ballot | 9/3/2015 | 9/11/2015 | Quorum: 85.81%<br>Approval: 91.61% | affirmative-9/1/1/1/1 | | |
| 537 | Project 2010-14.2.2 | Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAs DSEs and BAs ISDEs | Initial Ballot | 9/4/2015 | 9/14/2015 | Quorum: 81.81%<br>Approval: 90.91% | abstain-9/1/4/1/1 | | |
| 538 | Project 2015-04 | 2015-04 Alignment of Terms | Final Ballot | 9/4/2015 | 9/14/2015 | Quorum:<br>91.81%;91.11%;91.11%<br>Approval:<br>96.43%;97.11%;97.11%<br>NAY:0%;0%;0%<br>ABS:8.19%;8.89%;8.89%<br>Abstain:<br>7.1%;6.41%;6.41%<br>Approval:<br>96.43%;97.11%;97.11%<br>NAY:0%;0%;0%<br>ABS:8.19%;8.89%;8.89%<br>Abstain:<br>7.1%;6.41%;6.41%<br>Approval:<br>84.21%;85.18%;85.18%<br>Negative:<br>3.5%;3.16%;3.16%<br>Abstain:<br>7.1%;6.41%;6.41%<br>Approval:<br>84.21%;85.18%;85.18%<br>Negative:<br>3.5%;3.16%;3.16%<br>Abstain:<br>7.1%;6.41%;6.41%<br>Approval:<br>84.21%;85.18%;85.18%<br>Negative:<br>3.5%;3.16%;3.16%<br>Abstain:<br>7.1%;6.41%;6.41% | affirmative-7/2/6/1/1 | | |
| 539 | Project 2007-17.4 | Project 2007-17.4 PRC-005-NPCC Order No. 803 Revision | Initial Ballot | 9/8/2015 | 9/16/2015 | Quorum: 89.87%<br>Approval: 100% | affirmative-8/0/6/1/1 | | |
| 540 | Project 2010-05.1 | Project 2010-05.1 PRC-005-1b Order No. 803 Revision | Initial Ballot | 9/8/2015 | 9/16/2015 | Quorum: 89.87%<br>Approval: 87.26% | affirmative-9/0/6/1/1 | | |
| 541 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | Initial Ballot | 9/25/2015 | 10/5/2015 | Quorum: 89.87%<br>Approval: 87.26% | Negative-10/0/5/1 | | |
| 542 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Balancing Authority Reliability-based Controls-Reserves | Final Ballot | 9/25/2015 | 10/5/2015 | Quorum: 89.38%<br>Approval: 87.26% | affirmative-8/2/1/1/1 | | |
| 543 | Project 2010-05.3 | Project 2010-05.3a System Protection Coordination | Final Ballot | 9/25/2015 | 10/5/2015 | Quorum: 89.38%<br>Approval: 89.84% | affirmative-8/0/1/1 | | |
| 544 | Project 2010-05.3 | Project 2010-05.3 PRC-005-1b Order No. 803 Revision | Final Ballot | 9/8/2015 | 10/15/2015 | Quorum: 89.87%<br>Approval: 89.84% | affirmative-9/0/1/1 | | |
| 545 | Project 2007-17.4 | Project 2007-17.4 PRC-005-NPCC Order No. 803 Revision | Final Ballot | 10/15/2015 | 10/26/2015 | Quorum: 90.06%<br>Approval: 90.48% | affirmative-9/0/6/1/1 | | |
| 546 | Project 2010-05.3 | Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities | Initial Ballot | 10/28/2015 | 11/9/2015 | Quorum:<br>91.93%;91.49%<br>Approval:<br>84.93%;84.49% | abstain/non-11/5/1/1 | | |
| 547 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Balancing Authority Reliability-based Controls - BAs DSEs 2 | Initial Ballot | 11/5/2015 | 11/15/2015 | Quorum: 91.49%<br>Approval: 87.06% | affirmative-11/0/1/1 | | |
| 548 | Project 2015-07 | Project 2015-07 Internal Communications Capabilities | Initial Ballot | 11/6/2015 | 11/16/2015 | Quorum: 89.44%<br>Approval: 92.68% | affirmative-11/2/1/1 | | |
| 549 | Project 2007-06.2 | Project 2007-06.2 Phase 2 of System Protection Coordination | Additional Ballot | 11/23/2015 | 12/3/2015 | Quorum: 89.44%<br>Approval: 92.68% | affirmative-11/0/1/1 | | |
| 550 | Project 2010-07.2 | Project 2010-07.2 Generator Management | Initial Ballot | 12/7/2015 | 12/16/2015 | Quorum: 91.38%<br>Approval: 91.38% | Negative-12/0/1/1 | | |
| 547 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Balancing Authority Reliability-based Controls - BAs ISDEs 2 | Final Ballot | 11/6/2015 | 12/16/2015 | Quorum: 89.44%<br>Approval: 88.26% | affirmative-11/2/1/1 | | |
| 551 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | Additional Ballot | 11/30/2015 | 1/8/2016 | Quorum:<br>91.93%;89.44%<br>Approval:<br>84.93%;86.84% | affirmative-12/0/1/1 | | |
| 552 | Project 2010-14.2.2 | Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAs DSEs and BAs ISDEs | Additional Ballot | 12/31/2015 | 1/11/2016 | Quorum:<br>84.13%;83.17%;84.44%<br>Approval:<br>75.86%;75.61%;76.92% | NAI, DSEs 1 - Negative - 1/1/1/1<br>NAI, ISDEs - affirmative - 1/1/1/1<br>NAI, ISDEs 2 - Abstention - 1/1/0/1/1 | | |
| 553 | Project 2009-02 | Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities | Additional Ballot | 1/25/2016 | 1/05/2016 | Quorum:<br>91.86%;91.18%<br>Approval:<br>77.17%;80.51% | affirmative- 1/2/1/1/1 | | |
| 554 | Project 2010-07.2 | Project 2010-07.2 Generator Management | Final Ballot | 1/29/2016 | 2/8/2016 | Quorum:92.01%<br>Approval: 90.24% | affirmative- 2/1/1/1 | | |
| 552 | Project 2010-14.2.2 | Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAs DSEs and BAs ISDEs | Final Ballot | 1/29/2016 | 2/8/2016 | Quorum:<br>84.93%;84.94%;84.87%<br>Approval:<br>75.86%;75.61%;76.92% | affirmative- 2/1/1/1 | | |
| 555 | Project 2009-02 | Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities | Final Ballot | 2/17/2016 | 2/26/2016 | Quorum:<br>91.93%;91.74%<br>Approval:<br>75.84%;75.81% | affirmative- 1/2/1/1/1 | | |
| 552 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | Additional Ballot | 3/8/2016 | 4/18/2016 | Quorum: 75.41%<br>Approval: 90.91% | affirmative- 0/0/0/1/1 | | |
| 553 | Project 2007-06.2 | Project 2007-06.2 Phase 2 of System Protection Coordination | Initial Ballot | 4/25/2016 | 4/25/2016 | Quorum:<br>91.93%;91.11%<br>Approval:<br>84.11%;84.11% | affirmative- 4/2/0/1/1 | | |
| 554 | Project 2010-05.3 | Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS) | Final Ballot | 4/25/2016 | 4/25/2016 | Quorum:<br>91.93%;91.11%<br>Approval:<br>86.16%;85.11% | affirmative- 3/2/0/1/1 | | |
| 555 | Project 2015-07 | Project 2015-07 Internal Communications Capabilities | Additional Ballot | 4/27/2016 | 5/6/2016 | Quorum:<br>89.44%;89.11%<br>Approval: 92.31% | affirmative- 3/0/1/1 | | |
| 556 | Project 2007-06.2 | Project 2007-06.2 Phase 2 of System Protection Coordination | Final Ballot | 4/27/2016 | 5/06/2016 | Quorum:<br>89.44%;89.11%<br>Approval:<br>84.11%;84.11% | affirmative- 4/2/0/1/1 | | |
| 557 | Project 2015-07 | Project 2015-07 Internal Communications Capabilities | Final Ballot | 5/25/2016 | 6/04/2016 | Quorum:<br>91.11%;91.11%<br>Approval: 92.31% | affirmative- 3/0/1/1 | | |
| 558 | Project 2016-01 | Project 2016-01 Modifications to TOP and IRO Standards | Initial Ballot | 7/05/2016 | 8/5/2016 | Quorum:<br>91.11%;91.11%<br>Approval:<br>87.25%;88.33% | affirmative- 8/1/1/1 | | |
| 559 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2 | Initial Ballot | 8/8/2016 | 8/15/2016 | Quorum:<br>88.41%;89.11%;90.70%<br>Approval:<br>72.94%;74.81% | Negative- 8/0/1/1 | | |
| 560 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards | Initial Ballot | 8/28/2016 | 9/8/2016 | Quorum:<br>91.06%;91.11%;94.62%<br>Approval:<br>81.54%;81.77%;82.61% | Negative- 8/0/1/1 | | |
| 561 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-005-3 | Initial Ballot | 9/28/2016 | 9/8/2016 | Quorum: 91.11%<br>Approval: 92.31% | affirmative- 8/0/1/1 | | |
| 562 | Project 2015-MOD-01 | Project 2015-MOD-01 Integration of CIP-002-5.1 to Energy Sector Security Consortium (Dynegy) | Initial Ballot | 9/2/2016 | 9/12/2016 | Quorum: 91.06%<br>Approval: 91.06% | affirmative- 8/1/1/1 | | |
| 563 | Project 2016-01 | Project 2016-01 Modifications to TOP and IRO Standards | Additional Ballot | 10/5/2016 | 10/14/2016 | Quorum:<br>91.11%;91.11%<br>Approval:<br>75.77%;80.81% | affirmative- 10/1/1/1/1 | | |
| 564 | Project 2015-MOD-01 | Project 2015-MOD-01 Integration of CIP-002-5.1 to Energy Sector Security Consortium (Dynegy) | Final Ballot | 10/13/2016 | 10/24/2016 | Quorum: 91.11%<br>Approval: 91.11% | affirmative- 9/1/1/1 | | |
| 565 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards | Additional Ballot | 11/15/2016 | 12/5/2016 | Quorum:<br>91.11%;91.11%<br>Approval:<br>76.83%;78.21% | affirmative- 11/1/1/1 | | |
| 566 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3 | Additional Ballot | 11/30/2016 | 12/8/2016 | Quorum:<br>89.11%;89.11%<br>Approval:<br>76.83%;77.94% | affirmative- 11/0/0/1/1 | | |
| 567 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-008-2 | Final Ballot | 11/30/2016 | 12/8/2016 | Quorum: 91.11%<br>Approval: 76.83% | affirmative- 11/0/0/1/1 | | |
| 568 | Project 2016-01 | Project 2016-01 Modifications to TOP and IRO Standards | Final Ballot | 12/2/2016 | 12/12/2016 | Quorum:<br>91.11%;91.11%<br>Approval:<br>84.21%;85.18% | affirmative- 11/1/1/1 | | |
| 569 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards - CIP-002-5.1 and Implementation | Final Ballot | 12/8/2016 | 12/19/2016 | Quorum:<br>91.11%;91.11%<br>Approval:<br>87.26%;87.26% | affirmative- 12/1/1/1 | | |
| 570 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-008-2 | Additional Ballot | 12/28/2016 | 1/6/2017 | Quorum: 79.41%<br>Approval: 83.51% | affirmative- 1/0/1/1 | | |
| 571 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3 | Final Ballot | 12/28/2016 | 1/6/2017 | Quorum:<br>91.06%;91.11%<br>Approval:<br>83.51%;84.51% | affirmative- 1/0/1/1 | | |
| 572 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards - CIP-002-5.1 Implementation Plan and 2 Definitions | Initial Ballot | 1/24/2017 | 2/03/2017 | Quorum:<br>91.11%;91.11%;77.26%<br>Approval:<br>78.11%;<br>Negative:<br>87.62%;87.62%;70.<br>Abstain:<br>8%;8% | affirmative- 1/2/1/1 | | |
| 573 | Project 2016-03 | Project 2016-03 Cyber Security Supply Chain Risk Management | Initial Ballot | 1/24/2017 | 2/3/2017 | Quorum: 87.11% | Abstain- 0/3/1/1 | | |
| 574 | Project 2015-08 | Project 2015-08 Emergency Operations EOP-004-4 | Final Ballot | 1/24/2017 | 2/3/2017 | Approval: 92.86%<br>Quorum: 91.06%<br>Approval: 92.86% | affirmative- 1/0/1/1 | | |
| 575 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards - CIP-002-5.1 Implementation Plan and 2 Definitions | Final Ballot | 1/30/2017 | 2/8/2017 | Quorum:<br>91.11%;91.11%;84.21%<br>Approval:<br>78.11%;78.11%;81.81%<br>Negative:<br>87.62%;87.62%;70.8% | affirmative- 1/2/1/1 | | |
| 576 | IPW | Revisions to the NERC Standards Process Manual | Initial Ballot | 2/24/2017 | 3/3/2017 | Quorum: 79.41%<br>Approval: 84.72% | abstain- 0/3/1/1 | | |
| 577 | Project 2016-03 | Project 2016-03 Cyber Security Supply Chain Risk Management | Additional Ballot | 3/8/2017 | 3/17/2017 | Quorum:<br>91.11%;91.11%;77.11%<br>Approval:<br>84.21%;85.11%;88.24% | affirmative- 0/0/1/1 | | |
| 578 | Project 2016-03 | Project 2016-03 Cyber Security Supply Chain Risk Management | Final Ballot | 3/15/2017 | 3/24/2017 | Quorum:<br>91.11%;91.11%;81.84%<br>Approval:<br>84.21%;85.11%;88.24% | affirmative- 0/0/1/1 | | |
| 579 | Project 2015-03 | Project 2015-03 Emergency Response TPL-007-2 | Initial Ballot | 4/21/2017 | 4/11/2017 | Quorum: 72.81%<br>Approval: 72.81% | affirmative- 0/3/1/1 | | |
| 580 | Project 2014-04 | Project 2014-04 Modifications to PRC-023-3 | Initial Ballot | 4/21/2017 | 5/8/2017 | Quorum: 90.81%<br>Approval: 90.81% | affirmative- 0/3/1/1 | | |
| 581 | Project 2014-03 | Project 2014-03 Modifications to IAC Standards (of Disc 1-3 Control Center Communication Networks) | Initial Ballot | 4/24/2017 | 5/11/2017 | Quorum: 90.81%<br>Approval: 92.72% | affirmative- 0/3/1/1 | | |
| 582 | Project 2015-10 | Project 2015-10 Single Points of Failure TPL-001 | Initial Ballot | 9/8/2017 | 10/23/2017 | Quorum: 90.81%<br>Approval: 92.31% | abstain- -1/0/0/1 | | |
| 583 | Project 2015-03 | Project 2015-03 Emergency Response Initiative TPL-007-2 | Final Ballot | 10/20/2017 | 10/30/2017 | Quorum: 90.81%<br>Approval: 92.72% | affirmative- 0/3/1/1 | | |
| 584 | Project 2014-03 | Project 2014-03 Modifications to IAC Standards (of Disc 1-3) | Initial Ballot | 10/24/2017 | 10/30/2017 | Quorum: 90.81%<br>Approval: 92.86% | affirmative- 1/2/0/1/1 | | |
| 585 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Initial Ballot | 11/1/2017 | 11/13/2017 | Quorum:<br>87.11%;89.91%;89.91%<br>Approval:<br>89.11%;89.8%<br>Abstain:<br>7.9%;5.41%;5.41%<br>Approval:<br>89.11%;89.8%<br>Abstain:<br>7.9%;5.41%;5.41% | affirmative- 11/3/0/1/1 | | |
| 586 | Project 2010-02 | Project 2010-02 Modifications to IAC Standards (of Disc 1-3) | Additional Ballot | 11/20/2017 | 11/21/2017 | Quorum:<br>90.81%;91.11%<br>Approval:<br>84.21%;85.11% | affirmative- 12/3/1/1 | | |
| 587 | Project 2010-04 | Project 2010-04 Modifications to PRC-023-3 | Additional Ballot | 10/26/2017 | 11/13/2017 | Quorum: 90.81%<br>Approval: 88.21% | affirmative- 12/4/1/1 | | |
| 588 | Project 2014-04 | Project 2014-04 Modifications to PRC-023-4 | Final Ballot | 1/8/2018 | 1/18/2018 | Quorum: 91.81%<br>Approval: 88.89% | affirmative- 12/4/1/1 | | |
| 589 | Project 2017-02 | Project 2017-02 Modifications to Personnel Performance, Training and Qualifications | Initial Ballot | 2/28/2018 | 3/7/2018 | Quorum:<br>90.91%;91.11%<br>Approval:<br>77.14%;80.51% | affirmative- 3/2/1/1 | | |
| 590 | Project 2017-02 | Project 2017-02 Modifications to Personnel Performance, Training and Qualifications | Final Ballot | 4/5/2018 | 4/12/2018 | Quorum:<br>90.91%;91.11%<br>Approval:<br>78.41%;81.18% | affirmative- 3/2/1/1 | | |
| 591 | Project 2015-10 | Project 2015-10 Single Points of Failure TPL-001 | Additional Ballot | 12/5/2018 | 4/15/2018 | Quorum: 90.81%<br>Approval: 92.84% | affirmative- 4/0/1/1 | | |
| 592 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-4 | Additional Ballot | 4/16/2018 | 4/26/2018 | Quorum: 75.84%<br>Approval: 92.31% | affirmative- 4/0/1/1 | | |
| 593 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5 | Additional Ballot | 4/16/2018 | 4/26/2018 | Quorum: 90.81%<br>Approval: 92.72% | affirmative- 4/0/0/1 | | |
| 594 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5 Control Center Definition and Implementation Plan | Initial Ballot | 5/16/2018 | 6/06/2018 | Quorum:<br>91.81%;91.11%<br>Approval:<br>84.21%;85.11% | Negative- 4/3/1/1 | | |
| 595 | Project 2017-06 | Project 2017-06 Modifications to BAL-003-2 | Initial Ballot | 6/27/2018 | 7/6/2018 | Quorum: 90.81%<br>Approval: 89.8% | Abstain- 5/3/1/1 | | |
| 596 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5.1 | Additional Ballot | 5/28/2018 | 7/9/2018 | Quorum: 90.81%<br>Approval: 88.21% | affirmative- 4/2/0/1/1 | | |
| 597 | Project 2017-06 | Project 2017-06 Modifications to BAL-003-2 | Final Ballot | 7/5/2018 | 7/16/2018 | Quorum: 91.81%<br>Approval: 89.8% | Abstain- 5/3/1/1 | | |
| 598 | IPW | Revisions to the NERC Standards Process Manual | Additional Ballot | 7/31/2018 | 8/9/2018 | Quorum: 89.81%<br>Approval: 89.81% | affirmative- 6/2/1/1 | | |
| 599 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5.1 | Final Ballot | 8/6/2018 | 8/16/2018 | Quorum: 91.11%<br>Approval: 91.11% | affirmative- 4/2/0/1/1 | | |
| 600 | Project 2015-10 | Project 2015-10 Single Points of Failure TPL-001 | Additional Ballot | 9/5/2018 | 9/14/2018 | Quorum: 75.84%<br>Approval: 92.31% | affirmative- 4/3/1/1 | | |
| 601 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5 | Initial Ballot | 9/18/2018 | 10/8/2018 | Quorum: 90.81%<br>Approval: 92.68% | affirmative- 10/2/1/1 | | |
| 602 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5 | Initial Ballot | 9/28/2018 | 10/8/2018 | Quorum: 90.81%<br>Approval: 91.11% | affirmative- 10/2/1/1 | | |
| 603 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Additional Ballot | 10/8/2018 | 10/17/2018 | Quorum:<br>91.11%;91.11%;91.77%<br>Approval:<br>84.41%;85.41%;85.11%<br>Abstain:<br>7.69%;5.41%;5.41%<br>Approval:<br>84.41%;85.41%;85.11%<br>Abstain:<br>7.69%;5.41%;5.41% | affirmative- 10/1/1/1/1 | | |
| 604 | Project 2014-02 | Project 2014-02 Modifications to CIP-003-7 Cyber Security Vendor Reporting | Initial Ballot | 10/16/2018 | 10/25/2018 | Quorum: 91.11%<br>Approval: 100% | Negat- 10/2/1/1 | | |
| 605 | Project 2015-10 | Project 2015-10 Single Points of Failure TPL-001 | Final Ballot | 10/11/2018 | 10/21/2018 | Quorum: 90.38%<br>Approval: 92.31% | affirmative- 4/3/1/1 | | |
| 606 | IPW | Revisions to the NERC Standards Process Manual | Final Ballot | 10/17/2018 | 10/26/2018 | Quorum: 89.38%<br>Approval: 92.41% | affirmative- 4/7/1/1 | | |
| 607 | Project 2018-01 | Project 2018-01 Canadian specific Revisions to PRC-005-2 | Initial Ballot | 11/8/2018 | 11/13/2018 | Quorum: 91.11%<br>Approval: 100%100% | affirmative- 11/4/1/1 | | |
| 608 | Project 2014-02 | Project 2014-02 Modifications to CIP-003-7 Cyber Security Vendor Reporting | Additional Ballot | 11/20/2018 | 11/29/2018 | Quorum: 91.11%<br>Approval: 91.11% | affirmative- 11/0/1/1 | | |
| 609 | Project 2018-01 | Project 2018-01 Canadian specific Revisions to PRC-005-2 | Final Ballot | 11/29/2018 | 12/10/2018 | Quorum:<br>91.11%;91.11%<br>Approval:100%100% | affirmative- 11/4/1/1 | | |
| 610 | Project 2017-01 | Project 2017-01 Modifications to BAL-003-1.1 | Initial Ballot | 1/8/2019 | 1/17/2019 | Quorum: 92.91%92%<br>Approval: 92.91% | affirmative- 12/4/1/1 | | |
| 611 | Project 2018-02 | Project 2018-02 Modifications to CIP-008 Cyber Security Incident Reporting | Initial Ballot | 1/15/2019 | 1/25/2019 | Quorum: 91.11%<br>Approval: 91.11% | affirmative- 11/0/1/1 | | |
| 612 | Project 2018-03 | Project 2018-03 Standards Efficiency Review Retirements | Initial Ballot | 4/5/2019 | 4/15/2019 | Quorum:<br>91.11%;91.11%;91.11%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1% | affirmative- 4/2/0/1/1 for all standards except three<br>affirmative- 4/1/0/1/1 on following standard: PRC-004-5(i), INT-010-2-1 and PRC-005R-1 | | |
| 613 | Project 2014-02 | Project 2014-02 Modifications to CIP-003-7 | Initial Ballot | 4/18/2019 | 4/29/2019 | Quorum: 91.11%<br>Approval: 91.11% | affirmative- 10/0/1/1 | | |
| 614 | Project 2018-03 | Project 2018-03 Standards Efficiency Review Retirements | Final Ballot | 6/5/2019 | 6/15/2019 | Quorum:<br>91.11%;91.11%;91.11%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1% | affirmative- 4/2/0/1/1 for all standards except three | | |
| 615 | Project 2018-04 | Project 2018-04 Modifications to PRC-024-2 | Initial Ballot | 5/22/2019 | 6/21/2019 | Quorum: 90.88%<br>Approval: 92.41% | Abstain- 5/2/0/1/1 | | |
| 616 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-003-8 | Additional Ballot | 5/22/2019 | 5/31/2019 | Quorum: 91.11%<br>Approval: 87.26% | affirmative- 7/2/1/1 | | |
| 617 | Project 2019-01 | Project 2019-01 Modifications to TPL-007-3 | Initial Ballot | 8/28/2019 | 9/6/2019 | Quorum: 90.88%<br>Approval: 92.41% | affirmative- 6/2/1/1 | | |
| 618 | Project 2017-01 | Project 2017-01 Modifications to BAL-003-1.1 | Final Ballot | 10/30/2019 | 10/24/2019 | Quorum: 92.86%<br>Approval: 92.86% | affirmative- 5/2/1/1 | | |
| 619 | Project 2014-04 | Project 2014-04 Modifications to PRC-024-3 | Additional Ballot | 10/25/2019 | 11/14/2019 | Quorum: 90.88%<br>Approval: 89.67% | affirmative- 5/3/1/1 | | |
| 620 | Project 2019-01 | Project 2019-01 Modifications to TPL-007-3 | Final Ballot | 11/13/2019 | 11/22/2019 | Quorum: 90.88%<br>Approval: 92.41% | affirmative- 6/2/1/1 | | |
| 621 | Project 2017-07 | Project 2017-07 Standards Alignment with Registration | Initial Ballot | 11/21/2019 | 12/12/2019 | Quorum:<br>91.11%;90.11%;90.11%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89%<br>Abstain:<br>7.1%;7.1%;7.1%<br>Approval:<br>84.21%;84.21%;84.21%<br>NAY:0%;0%;0%<br>ABS:8.89%;8.89%;8.89% | affirmative- 12/1/1/1 | | |

**Link to Ballot Results:**
**https://standards.nerc.net/Ballots.aspx**
**(clicking in the column to the left of "Ballot Period" opens links to the Ballot Results)**

| Line | Project | Ballot Results | Ballot Type | Start Date | End Date (Initial Ballots Ending in Quorum) | Ballot Results | Recommendation / Date | Have NERS Voted | Comments |
|---|---|---|---|---|---|---|---|---|---|
| B22 | Project 2018-04 | Project 2018-04 Modifications to PRC-024-2 | Final Ballot | 11/8/2019 | 11/13/2019 | Quorum: 89.25%<br>Approval: 83.67% | Affirmative--11/6/19 | | |
| B23 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards CIP-002-5 | Additional Ballot | 11/1/2019 | 11/14/2019 | Quorum: 91.84%<br>Approval: 91.84% | Affirmative--11/11/19 | | |
| B24 | Technical Rationale For Reliability Standards | Technical Rationale for Reliability Standards | Non-binding Poll | 11/8/2019 | 11/18/2019 | Quorum:<br>85.45%RS 11%RS 85%<br>BA 11%RS 74%BA 15<br>MRL 17%RS 83%BA 7<br>Approval:<br>79.51%RS 89%RS 22%<br>BA 100%BA 0%<br>MRL 0%RS 0%MRL 1<br>0% | Affirmative--11/11/19 | | |
| B25 | Project 2017-07 | Project 2017-07 Standards Alignment with Registration | Final Ballot | 11/14/2019 | 11/15/2019 | Quorum:<br>84.11%RS 85%RS 0%R<br>15.96%RS 15%RS 84%<br>Approval:<br>93.44%RS 93%RS 0%R<br>100%RS 100%RS 0%<br>93.10%RS 93% | Affirmative--11/15/19 | | |
| B26 | Project 2019-02 | Project 2019-02 BES Cyber System Information Access Management | Initial Ballot | 1/24/2020 | 1/30/2020 | Quorum:<br>84.04%RS 78%RS 18%<br>Approval:<br>91.67%RS 94%RS 30% | Abstain--1/31/20 | | |
| B27 | Project 2019-03 | Project 2019-03 Cyber Security Supply Chain Risks | Initial Ballot | 12/17/2019 | 12/31/2019 | Quorum: 88.21%<br>Approval: 87.87% | Abstain--1/06/20 | | |
| B28 | Project 2014-02 | Project 2014-02 Modifications to CIP Standards CIP-002-5 | Final Ballot | 10/06/2020 | 10/16/2020 | Quorum: 87.91%<br>Approval: 86.28% | Affirmative--11/12/20 | | |
| B29 | Technical Rationale For Reliability Standards | Technical Rationale for Reliability Standards | Non-binding Poll | 6/30/2020 | 6/30/2020 | Quorum:<br>91.93%RS 12%RS 89%<br>BA 12%RS 64%BA 7%<br>MRL 2%<br>Approval:<br>100%RS 17%RS 12%<br>BA 100%RS 7%BA 1%<br>MRL 0%<br>96.93%RS 89%RS 0% | Affirmative--6/17/20 | | |
| B30 | Project 2019-03 | Project 2019-03 Cyber Security Supply Chain Risks | Additional Ballot | 9/11/2020 | 9/21/2020 | Quorum: 76.31%<br>Approval: 75.35% | Abstain--10/06/20 | | |
| B31 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Initial/Additional Ballot | 7/24/2020 | 8/06/2020 | Quorum:<br>91.48%RS 11%RS 20%<br>BA 11%RS 11%BA 0%<br>MRL 2%RS 2%MRL 0%<br>TSAS 4%<br>Approval:<br>93.16%RS 12%RS 20%<br>BA 100%RS 0%BA 0%<br>MRL 100%RS 2%MRL 0%<br>TSAS 100% | Affirmative--7/24/20 | | |
| B32 | Project 2019-02 | Project 2019-02 BES Cyber System Information Access Management | Additional Ballot | 9/11/2020 | 9/21/2020 | Quorum:<br>84.04%RS 81%RS 84%<br>Approval:<br>92.89%RS 89%RS 92% | Abstain--9/17/20 | | |
| B33 | Project 2019-03 | Project 2019-03 Cyber Security Supply Chain Risks | Final Ballot | 10/7/2020 | 10/16/2020 | Quorum: 87.91%<br>Approval: 78.71% | Abstain--10/06/20 | | |
| B34 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Additional Ballot | 11/17/2020 | 12/7/2020 | Quorum:<br>91.83%RS 11%<br>Approval:<br>91.61%RS 79% | Affirmative--12/6/20 | | |
| B35 | Project 2018-03 | Project 2018-03 Standards Efficiency Review Retirements | Initial Ballot | 4/5/2019 | 4/15/2019 | Quorum: 91.61%<br>Approval: 91.61%100% | Affirmative--1/8/21 | | |
| B36 | Project 2018-03 | Project 2018-03 Standards Efficiency Review Retirements | Final Ballot | 12/16/2021 | 12/26/21 | Quorum: 91.66%<br>Approval: 91.96% | Affirmative--1/8/21 | | |
| B37 | Project 2019-06 Cold Weather | Project 2019-06 Cold Weather | Initial Ballot | 9/9/2021 | 9/21/21 | Quorum:<br>84.11%RS 69%RS 87%<br>Approval:<br>84.19%RS 72%RS 87% | Affirmative--9/8/21 | | |
| B38 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards Virtualization | Initial Ballot | 5/12/2021 | 5/22/2021 | Quorum:<br>90.16%RS 93%RS 87%<br>89.67%RS 87%RS 24<br>BA 100%RS 0%BA 0<br>TSAS 11%RS 13%<br>Approval:<br>94.87%RS 93%RS 17%<br>BA 100%RS 0%BA 0<br>TSAS 100%RS 13%RS 22<br>MRL 100%RS 2%MRL 0<br>TSAS 100% | Abstain--5/17/21 | | |
| B39 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Additional Ballot | 12/9/2021 | 12/21/2021 | Quorum: 89.67%<br>Approval: 91.31% | Affirmative--3/31/21 | | |
| B40 | Project 2019-06 | Project 2019-06 Cold Weather | Additional Ballot | 9/1/2021 | 9/10/2021 | Quorum:<br>87.74%RS 59%RS 20%<br>Approval:<br>77.12%RS 41%RS 20% | Affirmative--9/8/21 | | |
| B41 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Final Ballot | 6/29/2021 | 5/10/2021 | Quorum:<br>91.91%RS 64%RS 20%<br>89.41%RS 47%RS 24<br>BA 100%RS 0%BA 0<br>TSAS 11%<br>Approval:<br>94.12%RS 64%RS 55%<br>BA 17%RS 15%RS 20<br>MRL 100%RS 1%MRL 0<br>TSAS 100% | Affirmative--3/31/21 | | |
| B42 | Project 2015-09 | Project 2015-09 Establish and Communicate System Operating Limits | Final Ballot | 10/29/2021 | 11/10/2021 | Quorum: 90.45%<br>Approval: 78.91% | Affirmative--3/31/21 | | |
| B32 | Project 2019-02 | Project 2019-02 BES Cyber System Information Access Management | Additional Ballot | 12/1/2021 | 12/10/2021 | Quorum:<br>84.51%RS 61%RS 84%<br>Approval:<br>82.71%RS 39%RS 92% | Affirmative--4/30/21 | | |
| B40 | Project 2019-06 | Project 2019-06 Cold Weather | Final Ballot | 12/8/2021 | 12/17/2021 | Quorum:<br>90.62%RS 44%RS 24%<br>Approval:<br>78.24%RS 20%RS 32% | Affirmative--3/31/21 | | |
| B43 | Project 2020-04 | Project 2020-04 Modifications to CIP-012 | Initial Ballot | 4/26/2021 | 5/6/2021 | Quorum:<br>85.84%RS 67%<br>Approval:<br>77.11%RS 72% | Abstain--4/7/21 | | |
| B42 | Project 2019-02 | Project 2019-02 BES Cyber System Information Access Management | Final Ballot | 6/2/2021 | 6/11/2021 | Quorum:<br>84.51%RS 61%RS 87%<br>Approval:<br>84.19%RS 39%RS 17% | Affirmative--4/30/21 | | |
| B43 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards Virtualization | Additional Ballot | 8/23/2021 | 9/1/2021 | Quorum:<br>87.04%RS 58%RS 88%<br>Approval:<br>94.87%RS 50%RS 93%<br>BA 100%RS 0%BA 0<br>TSAS 100%RS 8%<br>MRL 100%RS 1%MRL 0<br>TSAS 100%<br>Approval:<br>86.21%RS 55%TSAS 89%<br>BA 100%RS 0%BA 0<br>MRL 100%RS 1%MRL 0<br>TSAS 100%RS 8% | Abstain--8/25/21 | | |
| B44 | Project 2020-03 | Project 2020-03 Supply Chain Low Impact Revisions | Initial Ballot | 10/8/2021 | 10/21/2021 | Quorum:<br>81.56%RS 81%<br>Approval:<br>72.69%RS 50% | Abstain--10/7/21 | | |
| B45 | Project 2020-04 | Project 2020-04 Modifications to CIP-012 | Additional Ballot | 1/14/2022 | 1/24/2022 | Quorum:<br>81.84%RS 72%<br>Approval:<br>79.64%RS 77% | Abstain--1/24/22 | | |
| B46 | Project 2020-05 | Project 2020-05 Modifications to FAC-001 and FAC-002 | Initial Ballot | 1/21/2022 | 1/31/2022 | Quorum:<br>76.67%RS 35%<br>Approval:<br>94.87%RS 50% | Affirmative--1/31/22 | | |
| B47 | Project 2016-02 | Project 2016-02 Modifications to CIP Standards Virtualization | Additional Ballot | 4/1/2022 | 4/12/2022 | Quorum:<br>81.05%RS 35%RS 25%<br>Approval:<br>94.12%RS 35%RS 0<br>MRL 25%RS 0%MRL 0<br>TSAS 0%RS 25%<br>Approval:<br>72.06%TS 41%TS 0%<br>BA 0%TS 0%BA 0<br>TG 0%TS 0%TG 0%TSAS 0<br>76TS 0%TS 0 0% | Abstain--4/7/22 | | |
| B48 | Project 2020-03 | Project 2020-03 Supply Chain Low Impact Revisions | Additional Ballot | 2/25/2022 | 4/15/2022 | Quorum:<br>81.51%RS 35%<br>Approval:<br>72.13%RS 15% | Abstain--4/7/22 | | |
| B49 | Project 2020-05 | Project 2020-05 Modifications to FAC-001 and FAC-002 | Final Ballot | 4/12/2022 | 4/22/2022 | Quorum:<br>84.84%RS 35%<br>Approval:<br>94.84%RS 35% | Affirmative--3/31/22 | | |
| B50 | Project 2021-07 | Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination | Initial Ballot | 4/8/2022 | 4/21/2022 | Quorum:<br>84.84%RS 35%<br>Approval:<br>72.94%RS 20% | Abstain--4/14/22 | | |
| B51 | Project 2020-06 | Project 2020-06 Verifications of Models and Data for Generators | Initial Ballot | 4/27/2022 | 5/6/2022 | Quorum:<br>82.24%RS 35%<br>Approval:<br>94.24%RS 35% | Abstain--4/29/22 | | |
| B52 | Project 2021-04 | Project 2021-04 Modifications to PRC-002 | Initial Ballot | 7/15/2022 | 7/25/2022 | Quorum:<br>86.94%RS 35%<br>Approval:<br>96.94%RS 35% | Abstain--7/22/22 | | |

**RSC Meeting #23-4, Agenda Item 4.3: Comment History**
(As of 10/6/2023)

| 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 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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 | |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 53. | N/A | CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages | CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002 | | 10/19/11 | 11/9/11 | |
| 54. | N/A | CAN-0030--Attestations | CAN-0030 | | 10/19/11 | 11/9/11 | |
| 55. | Project 2011-INT-01 | Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company | MOD-028, R3.1 | | 10/3/11 | 11/16/11 | Yes 11/16/11 |
| 56. | Project 2009-22 | Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC | Interpretation of COM-002-2, R2 | | 10/4/11 | 11/18/11 | Yes 11/18/11 |
| 57. | Project 2010-07 | Project 2010-07 - Generator Requirements at the Transmission Interface | Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards | | 10/5/11 | 11/18/11 | Yes 11/18/11 |
| 58. | N/A | Draft Directive Regarding Generator Transmission Leads | Draft Directive #2011 CAG-001 | | 10/17/11 | 11/18/11 | Yes 11/18/11 |
| 59. | Project 2008-10 | Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy | Interpretation of CIP-006-1, R1.1 | | 10/12/11 | 11/21/11 | Yes 11/21/11 |
| 60. | N/A | CAN-0040 - BAL-003 Frequency Bias Calculation | | | 11/2/11 | 11/23/11 | |
| 61. | N/A | CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence | PRC-005 Evidence | | 11/2/11 | 11/23/11 | Yes 11/22/11 |
| 62. | Project 2007-12 | Project 2007-12 - Frequency Response | BAL-003-1 | | | 12/8/11 | Yes 12/8/11 |
| 63. | Project 2009-01 | Project 2009-01 - Disturbance and Sabotage Reporting | EOP-004-2 | | | 12/12/11 | Yes 12/12/11 |
| 64. | N/A | Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages | CAN-0027 TOP-003, R2 | | 11/22/11 | 12/14/11 | |
| 65. | NERC RoP | Proposed Changes to the NERC Rules of Procedure and Associated Appendices | | | 11/7/11 | 12/22/11 | |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 66. | NERC RoP | Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011 | | | 11/22/11 | 12/22/11 | |
| 67. | Regional Standard | Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding | PRC-006-NPCC-1 | | 11/22/11 | 12/22/11 | |
| 68. | Project 2008-06 | Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards) | Version 5 CIP Standards | | 11/7/11 | 1/6/12 | Yes 1/6/12 |
| 69. | Project 2007-03 | Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2 | TOP-001-2<br>TOP-002-3<br>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<br>COM-002<br>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 | |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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 | |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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<br>INT-006-4<br>INT-009-2<br>INT-010-2<br>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<br>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<br>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 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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<br>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<br>FAC-008-3<br>FAC-010-2.1<br>FAC-011-2<br>FAC-013-2<br>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<br>EOP-002-3.1<br>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<br>IRO-004-2<br>IRO-005-4<br>IRO-006-5<br>IRO-006-East<br>IRO-008-1<br>IRO-009-1<br>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)<br>PRC-005-3(X)<br>PRC-005-X(X)<br>VAR-002-2b(X)<br>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<br>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<br>PRC-020<br>PRC-021<br>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<br>TOP-002-4<br>TOP-003-3<br>IRO-001-4<br>IRO-002-4 | Formal | 05/19/14 | 07/02/14 | Yes 7/2/14 |

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| | | | IRO-008-2<br>IRO-010-2<br>IRO-014-3<br>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)<br>PRC-005-3(X)<br>PRC-005-X(X)<br>VAR-002-2b(X)<br>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<br>PRC-020<br>PRC-021<br>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<br>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)<br>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<br>TOP-002-4<br>TOP-003-3<br>IRO-001-4<br>IRO-002-4<br>IRO-008-2<br>IRO-010-2<br>IRO-014-3<br>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)<br>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<br>CIP-010-2<br>CIP-003-X<br>CIP-004-X<br>CIP-007-X<br>CIP-010-X<br>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<br>FAC-011-3<br>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<br>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<br>PRC-005-2<br>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<br>EOP-005-2<br>EOP-006-2<br>EOP-008-1 | Informal | 7/21/15 | 8/19/15 | Yes 8/19/15 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 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<br>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<br>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<br>PER-003-1<br>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 |

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|---|---|---|---|---|---|---|---|
| | | 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 |

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|---|---|---|---|---|---|---|---|
| 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<br>FAC-011<br>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<br>INT-006-4<br>INT-009-2.1<br>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<br>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 |

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|---|---|---|---|---|---|---|---|
| 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<br>FAC-011<br>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 |

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|---|---|---|---|---|---|---|---|
| 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<br>INT-006-5<br>INT-009-3<br>IRO-002-6<br>PRC-004-6<br>TOP-001-5<br>VAR-001-6<br>FAC-013-2<br>INT-004-3.1<br>INT-010-2.1<br>MOD-001-1a<br>MOD-004-1<br>MOD-008-1<br>MOD-020-0<br>MOD-028-2<br>MOD-029-2a<br>MOD-030-3<br>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<br>CIP-010-3<br>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<br>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<br>IRO-010-3<br>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<br>NUC-001-4<br>PRC-006-4<br>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<br>IRO-002-6<br>IRO-006-East-2<br>IRO-008-2<br>IRO-009-2<br>IRO-010-2<br>IRO-014-3<br>IRO-017-1<br>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<br>CIP-010-3<br>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<br>IRO-002-6<br>IRO-006-East-2<br>IRO-008-2<br>IRO-009-2<br>IRO-010-2<br>IRO-014-3<br>IRO-017-1<br>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<br>MOD-026<br>MOD-027<br>PRC-019<br>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<br>CIP-010-3<br>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<br>FAC-003-5<br>FAC-011-4<br>FAC-013-3<br>FAC-014-3<br>PRC-002-3<br>PRC-026-2<br>TOP-001-6<br>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<br>CIP-010-4<br>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<br>FAC-003-5<br>FAC-011-4<br>FAC-013-3<br>FAC-014-3<br>PRC-002-3<br>PRC-026-2<br>TOP-001-6<br>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<br>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<br>IRO-010-4<br>TOP-003-5 | Formal | 1/27/21 | 3/12/21 | Yes 3/12/21 |
| 433 | Project 2019-06 | Cold Weather | EOP-011-2<br>IRO-010-4<br>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<br>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<br>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<br>CIP-003-Y<br>CIP-004-Y<br>CIP-005-8<br>CIP-006-7<br>CIP-007-7<br>CIP-008-7<br>CIP-009-7<br>CIP-010-5<br>CIP-011-Y<br>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<br>EOP<br>IRO<br>TOP<br>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<br>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<br>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<br>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 |
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|---|---|---|---|---|---|---|---|
| 452 | Project 2016-02 | Modifications to CIP Standards | CIP-002-7<br>CIP-003-Y<br>CIP-004-Y<br>CIP-005-8<br>CIP-006-7<br>CIP-007-7<br>CIP-008-7<br>CIP-009-7<br>CIP-010-5<br>CIP-011-Y<br>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<br>PER-005-2<br>PER-006-1<br>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<br>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<br>MOD-032<br>TPL-001 | Formal | 8/11/22 | 9/13/22 | Yes 9/13/22 |
| 465 | Project 2016-02 | Modifications to CIP Standards | CIP-002-7<br>CIP-003-Y<br>CIP-004-Y<br>CIP-005-8<br>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<br>CIP-008-7<br>CIP-009-7<br>CIP-010-5<br>CIP-011-Y<br>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<br>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 |
| 470 | Project 2021-06 | Modifications to IRO-010 and TOP-003 | IRO-010-2<br>TOP-003-3 | Formal | 10/25/22 | 12/15/22 | Yes 12/15/22 |
| 471 | Project 2021-03 | CIP-002 Transmission Owner Control Centers | CIP-002 | Formal | 11/22/22 | 12/21/22 | Yes 12/21/22 |
| 472 | Project 2021-02 | Modifications to VAR-002 | VAR-002-4.1 | Formal | 10/31/22 | 1/13/23 | Yes 1/13/23 |
| 473 | Project 2020-06 | Verifications of Models and Data for Generators | MOD-26-2 | Formal | 11/21/22 | 1/18/23 | Yes 1/18/23 |
| 474 | SPM | Standard Processes Manual | SPM | Formal | 1/18/23 | 3/6/23 | Yes 3/6/23 |
| 475 | Project 2022-01 | Reporting ACE Definition and Associated Terms | ACE Definition Master List | Formal | 1/31/23 | 3/16/23 | Yes 3/16/23 |
| 476 | Project 2023-02 | Performance of IBRs | PRC-004-6 | Formal | 2/22/23 | 3/23/23 | Yes 3/23/23 |
| 477 | Project 2021-03 | CIP-002 Transmission Owner Control Centers | CIP-002 | Formal | 3/2/23 | 3/31/23 | Yes 3/31/23 |
| 478 | Project 2021-07 | Extreme Cold Weather Grid Operations, Preparedness, and Coordination | EOP-011-4<br>TOP-002-5 | Formal | 2/28/23 | 4/13/23 | Yes 4/13/23 |
| 479 | Project 2023-03 | Internal Network Security Monitoring (INSM) | CIP-005-7<br>CIP-010-4<br>CIP-013-2 | Formal | 4/6/23 | 5/5/23 | Yes 5/5/23 |
| 480 | Project 2022-02 | Modifications to TPL-001 and MOD-032 | TPL-001<br>MOD-032 | Informal | 4/13/23 | 5/12/23 | Yes 5/12/23 |
| 481 | Project 2023-04 | Modifications to CIP-003 | CIP-003-9 | Formal | 3/31/23 | 5/15/23 | Yes 5/15/23 |
| 482 | SPM | Standard Processes Manual | Appendix 3A | Formal | 4/13/23 | 5/30/23 | Yes 5/30/23 |
| 483 | Project 2017-01 | Modifications to BAL-003 – Phase II | BAL-003-2 | Formal | 4/18/23 | 6/1/23 | Yes 6/1/23 |

| Line | Project# | Description | Document | Comment Type | Start Date | End Date | NPCC Submitted |
|---|---|---|---|---|---|---|---|
| 484 | Project 2021-01 | Modifications to MOD-025 and PRC-019 | MOD-025-2 PRC-019-2 | Formal | 4/25/23 | 6/8/23 | Yes 6/8/23 |
| 485 | Project 2021-06 | Modifications to IRO-010 and TOP-003 | IRO-010-2 TOP-003-3 | Formal | 5/5/23 | 6/21/23 | Yes 6/21/23 |
| 486 | Project 2021-02 | Modifications to VAR-002 | VAR-002-4.1 | Formal | 5/10/23 | 6/23/23 | Yes 6/23/23 |
| 487 | Project 2021-03 | CIP-002 | CIP-002 | Informal | 6/13/23 | 7/12/23 | Yes 7/12/23 |
| 488 | Project 2022-02 | Modifications to TPL-001 and MOD-032 | TPL-001 MOD-032 | Formal | 5/13/23 | 7/14/23 | Yes 7/14/23 |
| 489 | Project 2021-03 | CIP-002 | CIP-002 | Formal | 7/20/23 | 8/18/23 | Yes 8/18/23 |
| 490 | RSDP | Reliability Standards Development Plan | RSDP | Informal | 7/24/23 | 8/22/23 | Yes 8/22/23 |
| 491 | Project 2023-06 | CIP-014 Risk Assessment Refinement | CIP-014 | Formal | 7/26/23 | 8/24/23 | Yes 8/23/23 |
| 492 | Project 2023-05 | Modifications to FAC-001 and FAC-002 | FAC-001-4 FAC-002-4 | Formal | 8/9/23 | 9/7/23 | Yes 9/7/23 |
| 493 | Project 2023-01 | EOP-004 IBR Event Reporting | EOP-004-5 | Formal | 7/28/23 | 9/11/23 | Yes 9/11/23 |
| 494 | Project 2021-07 | Extreme Cold Weather Grid Operations, Preparedness, and Coordination | EOP-011-4 TOP-002-5 | Formal | 8/24/23 | 9/12/23 | Yes 9/12/23 |
| 495 | Project 2021-04 | Modifications to PRC-002 | PRC-002-3 PRC-028-1 | Formal | 8/1/23 | 9/14/23 | Yes 9/14/23 |
| 496 | Project 2023-07 | Modifications to TPL-001-5.1 Transmission System Planning Performance Requirements for Extreme Weather | TPL-001-5.1 | Informal | 8/29/23 | 9/27/23 | Yes 9/27/23 |
| 497 | Project 2022-03 | Energy Assurance with Energy-Constrained Resources | TOP-0XX-X | Formal | 9/13/23 | 10/5/23 | Yes 10/5/23 |
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*Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."*

# 2023 REGIONAL STANDARDS COMMITTEE

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