Agenda Standards Committee Meeting
June 14, 2017 | 10:00 a.m. to 3:00 p.m. Eastern


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Introduction and Chair’s Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Agenda Items

1. Review June 14 Agenda — (Approve) (B. Murphy) (1 minute)

2. Consent Agenda — (Approve) (B. Murphy) (1 minute)
   a. April 19, 2017 Standards Committee Meeting Minutes* — (Approve)
   b. May 1, 2017 Standards Committee Special Call Minutes* — (Approve)
   c. PMOS Vice Chair Selection* — (Endorse)

3. Upcoming Standards Projects or Issues* — (Update)
   a. Three-Month Outlook* (S. Noess; B. Murphy) (10 minutes)

4. Projects Under Development — (Review)
   a. Project Tracking Spreadsheet (C. Yeung) (10 minutes)
   b. Projected Posting Schedule (S. Noess) (5 minutes)

5. Project 2013-03 Geomagnetic Disturbance Mitigation
   a. Posting of TPL-007-2* — (Authorize); and
   b. Project Schedule* — (Approve) (S. Kim) (10 minutes)

6. BAL-002-2 Standard Authorization Request* — (Accept); and Standard Drafting Team* — (Appoint) (S. Kim) (10 minutes)

7. BAL-003-1.1 Standard Authorization Request and SAR Drafting Team Nominations* — (Authorize) (S. Kim) (10 minutes)

8. Project 2016-EPR-01 Enhanced Periodic Review of PER-003-1 and PER-004-2* — (Accept); Standard Authorization Requests* — (Authorize); and Standard Drafting Team* — (Appoint) (S. Kim) (10 minutes)
9. **Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards*** — (Accept) (S. Kim) (5 minutes)
10. **Project 2016-EPR-02 Errata of VAR-001-4.1 and VAR-002-4*** — (Approve) (S. Kim) (5 minutes)
11. **Reliability Standards Development Plan*** — (Endorse) (S. Cavote) (5 minutes)
12. **Technical Rationale for Reliability Standards*** — (Endorse) (S. Noess) (10 minutes)
13. **Request for Interpretation EOP-008-1 R4*** — (Reject) (S. Cavote) (5 minutes)
14. **Request for Interpretation PRC-006-2 R9*** — (Reject) (S. Cavote) (5 minutes)
15. **Project to Review/Revise the Periodic Review Template*** — (Endorse) (B. Li) (5 minutes)
16. **Subcommittee Reports and Updates**
   a. **Project Management and Oversight Subcommittee** — (Update) (C. Yeung) (5 minutes)
   b. **Process Subcommittee*** — (Update) (B. Li) (5 minutes)
17. **Legal Update, Upcoming Standards Filings*** — (Review) (L. Perotti) (5 minutes)
18. **Informational Items** — (Enclosed)
   a. **Compliance and Certification Committee (CCC) Data Retention**
   b. **Compliance Filing to Change BAL-002-2 VRFs**
   c. **Standards Committee Expectations**
   d. **2017 Meeting Dates and Locations**
   e. **2017 Standards Committee Roster**
   f. **Highlights of Parliamentary Procedure**
19. **Adjournment**

*Background materials included.
Antitrust Compliance Guidelines

I. General
It is NERC’s policy and practice to obey the antitrust laws and to avoid all conduct that unreasonably restrains competition. This policy requires the avoidance of any conduct that violates, or that might appear to violate, the antitrust laws. Among other things, the antitrust laws forbid any agreement between or among competitors regarding prices, availability of service, product design, terms of sale, division of markets, allocation of customers or any other activity that unreasonably restrains competition.

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

Antitrust laws are complex and subject to court interpretation that can vary over time and from one court to another. The purpose of these guidelines is to alert NERC participants and employees to potential antitrust problems and to set forth policies to be followed with respect to activities that may involve antitrust considerations. In some instances, the NERC policy contained in these guidelines is stricter than the applicable antitrust laws. Any NERC participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NERC’s antitrust compliance policy is implicated in any situation should consult NERC’s General Counsel immediately.

II. Prohibited Activities
Participants in NERC activities (including those of its committees and subgroups) should refrain from the following when acting in their capacity as participants in NERC activities (e.g., at NERC meetings, conference calls and in informal discussions):

- Discussions involving pricing information, especially margin (profit) and internal cost information and participants’ expectations as to their future prices or internal costs.
- Discussions of a participant’s marketing strategies.
- Discussions regarding how customers and geographical areas are to be divided among competitors.
- Discussions concerning the exclusion of competitors from markets.
- Discussions concerning boycotting or group refusals to deal with competitors, vendors or suppliers.
• Any other matters that do not clearly fall within these guidelines should be reviewed with NERC’s General Counsel before being discussed.

III. Activities That Are Permitted
From time to time decisions or actions of NERC (including those of its committees and subgroups) may have a negative impact on particular entities and thus in that sense adversely impact competition. Decisions and actions by NERC (including its committees and subgroups) should only be undertaken for the purpose of promoting and maintaining the reliability and adequacy of the bulk power system. If you do not have a legitimate purpose consistent with this objective for discussing a matter, please refrain from discussing the matter during NERC meetings and in other NERC-related communications.

You should also ensure that NERC procedures, including those set forth in NERC’s Certificate of Incorporation, Bylaws, and Rules of Procedure are followed in conducting NERC business.

In addition, all discussions in NERC meetings and other NERC-related communications should be within the scope of the mandate for or assignment to the particular NERC committee or subgroup, as well as within the scope of the published agenda for the meeting.

No decisions should be made nor any actions taken in NERC activities for the purpose of giving an industry participant or group of participants a competitive advantage over other participants. In particular, decisions with respect to setting, revising, or assessing compliance with NERC reliability standards should not be influenced by anti-competitive motivations.

Subject to the foregoing restrictions, participants in NERC activities may discuss:

• Reliability matters relating to the bulk power system, including operation and planning matters such as establishing or revising reliability standards, special operating procedures, operating transfer capabilities, and plans for new facilities.
• Matters relating to the impact of reliability standards for the bulk power system on electricity markets, and the impact of electricity market operations on the reliability of the bulk power system.
• Proposed filings or other communications with state or federal regulatory authorities or other governmental entities.

Matters relating to the internal governance, management and operation of NERC, such as nominations for vacant committee positions, budgeting and assessments, and employment matters; and procedural matters such as planning and scheduling meetings.
Public Announcements

REMINDER FOR USE AT BEGINNING OF MEETINGS AND CONFERENCE CALLS THAT HAVE BEEN PUBLICLY NOTICED AND ARE OPEN TO THE PUBLIC

For face-to-face meeting, with dial-in capability:
Participants are reminded that this meeting is public. Notice of the meeting was posted on the NERC website and widely distributed. The notice included the number for dial-in participation. Participants should keep in mind that the audience may include members of the press and representatives of various governmental authorities, in addition to the expected participation by industry stakeholders.
B. Murphy, chair, called to order the meeting of the Standards Committee (SC or the Committee) on April 19, 2017, at 1:00 p.m. Eastern. After the roll call by C. Larson, secretary, meeting quorum was declared. The SC member attendance and proxy sheet is attached hereto as Attachment 1.

NERC Antitrust Compliance Guidelines and Public Announcement
Committee secretary called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice. He asked that any questions regarding the NERC Antitrust Compliance Guidelines be directed to NERC’s General Counsel, Charles Berardesco.

Introduction and Chair’s Remarks
B. Murphy welcomed the Committee and guests. He stated there may be a special call in May to support the timeline of Project 2016-03 Cyber Security Supply Chain Management.

Review April 19, 2017 Agenda (agenda item 1)
Approved by unanimous consent including waiver of five-day rule.

Consent Agenda (agenda item 2)
Motion to adopt March 15, 2017 Standards Committee Meeting Minutes
Approved by unanimous consent.

Upcoming Standards Projects or Issues (agenda item 3)
Three-Month Outlook
S. Noess provided highlights of the Three-Month Outlook. He fielded questions from SC Members regarding Project 2016-03.

Projects Under Development (agenda item 4)
Project Tracking Spreadsheet
C. Yeung reviewed the Project Tracking Spreadsheet.

Projected Posting Schedule
S. Noess reviewed the Projected Posting Schedule. There were no comments or questions from the SC or observers.
Project 2016-04 Modifications to PRC-025-1 (agenda item 5)
C. Gowder made the motion to accept the action item as written; S. Bodkin seconded. B. Murphy brought the motion to a vote. The motion was as follows:

Accept the Standard Authorization Request (SAR) to modify Reliability Standard PRC-025-1. Appoint the SAR drafting team (DT) as the standard drafting team (SDT), less the current DT chair, and appoint team member #6, currently the DT vice chair, as the SDT chair, and appoint team member #5 as SDT vice chair.

The Committee approved the motion with no objections. The following SDT members were appointed.

- John Schmall, chair, Electric Reliability Council of Texas (ERCOT)
- Mike Jensen, vice chair, Pacific Gas and Electric Company (PG&E)
- Juan Alvarez, Caithness Energy
- Samuel (Bryan) Burch, Southern Company
- Walter Campbell, NextEra Energy Resources, LLC
- Jason Espinosa, Seminole Electric Cooperative, Inc.

2017 Periodic Review Team Nomination Solicitation (agenda item 6)
G. Zito made the motion to accept the action item as written; S. Miller seconded. The motion was as follows:

Authorize posting for nominations for Periodic Review team members for the following Periodic Reviews: (1) FAC-008; (2) INT-004, INT-006, INT-009, and INT-010; and (3) NUC-001-3.

The Committee approved the motion with no objections or abstentions.

Standard Authorization Request of PRC-005 and Stationary Battery Maintenance (agenda item 7)
J. Bussman made the motion to accept the action item as written; R. Crissman seconded. J. Bussman stated he spoke with System Protection and Control Subcommittee (SPCS) member to better understand the background, and J. Bussman agreed with the reasoning provided in the agenda package. S. Rueckert asked if the SPCS had discussed this with the Institute of Electrical and Electronics Engineers (IEEE). The SPCS member stated that they had a discussion with the IEEE committee, and came to the conclusion that the standard requirements for battery testing are adequate, and that additional testing by an entity would be acceptable. The motion was as follows:
Reject the SAR submitted by the IEEE Stationary Battery Committee concerning PRC-005 and stationary battery maintenance, and direct the SC chair to provide the SAR sponsor a written explanation for rejection within 10 days.

*The Committee approved the motion with no objections or abstentions.*

**Managing Changes to Implementation Plan Prior to Posting for Final Ballot (agenda item 8)**

G. Zito made the motion to accept the action item as written; D. Kiguel seconded. J. Bussman expressed concern that the SC and Standards Committee Process Subcommittee (SCPS) recently completed a project revising the Drafting Team Reference Manual, and waiting for the periodic revision would delay direction to the drafting teams. G. Zito responded that the motion, as written, instructed NERC staff to provide interim guidance to the individual drafting teams on seeking approval from the SC if questions arise regarding whether changes to Implementation Plans are substantive enough to warrant posting for comment. It was noted that taking an implementation plan change to the SC under this process would be seldom used. The motion was as follows:

Endorse the following approach to manage changes to the implementation plan for draft standards just prior to the standards being posted for final ballot:

a. Revise the Drafting Team Reference Manual (DTRM) during the next scheduled review to prompt standard drafting teams to seek advice and determination from the SC on whether changes to implementation plans are “substantive,” and therefore, require the draft implementation plan or standard(s) to be posted for an additional comment period and ballot prior to conducting final ballot.

b. Prior to making the above DTRM changes, request NERC staff to convey the above guidance to all standard drafting teams at their next meetings.

c. Have the SCPS revisit this approach in 12-18 months to evaluate the need for further action, which may include developing criteria or guidance to assist the drafting team in assessing whether certain type of changes to an implementation plan would be deemed “non-substantive” (thereby eliminating the need to seek a determination from the SC).

*The Committee approved the motion with no objections or abstentions.*

**Subcommittee Reports and Updates (agenda item 9)**

**Project Management and Oversight Subcommittee**

C. Yeung provided an update of Project Management and Oversight Subcommittee (PMOS) activities. The vice chair role is currently open, and PMOS is soliciting nominations for the next meeting.
Process Subcommittee
B. Li provided an update of SCPS activities. The vice chair role is currently open, and SCPS is soliciting nominations for the next meeting. He highlighted the Standard Processes Manual comment period within the SCPS work plan.

Legal Update (agenda item 10)
L. Perotti provided her update regarding recent and upcoming Standards Filings.

Informational Items (agenda item 11)
No discussion on informational items.

Adjourn
B. Murphy thanked the Committee members and adjourned the meeting at 1:50 p.m. Eastern.
## Attachment I

<table>
<thead>
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<th>Organization</th>
<th>Proxy</th>
<th>Present (Member or Proxy)</th>
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</table>
| Chair 2016-17    | Brian Murphy  
Senior Attorney                  | NextEra Energy, Inc.                        |       | Yes                       |
| Vice-Chair 2016-17 | Michelle D’Antuono  
Manager, Energy               | Occidental Energy Ventures, LLC            |       | Yes                       |
| Segment 1-2016-17 | Laura Lee  
Manager of ERO Support and Event Analysis, System Operations | Duke Energy                               | Colby Bellville | Yes                       |
| Segment 1-2017-18 | Sean Bodkin  
NERC Compliance Policy Manager | Dominion Resources Services, Inc.          |       | Yes                       |
| Segment 2-2016-17 | Ben Li  
Consultant                     | Independent Electric System Operator      |       | Yes                       |
| Segment 2-2017-18 | Charles Yeung  
Executive Director Interregional Affairs | Southwest Power Pool                      |       | Yes                       |
| Segment 3-2016-17 | Scott Miller  
Manager Regulatory Policy       | MEAG Power                                 |       | Yes                       |
| Segment 3-2017-18 | John Bussman  
Manager, Reliability Compliance | Associated Electric Cooperative, Inc.      |       | Yes                       |
| Segment 4-2016-17 | Chris Gowder  
Regulatory Compliance Specialist | Florida Municipal Power Agency            |       | Yes                       |
| Segment 4-2017-18 | Barry Lawson  
Associate Director, Power Delivery and Reliability | National Rural Electric Cooperative Association | No     |                           |
| Segment 5-2016-17 | Randy Crissman  
Vice President – Technical Compliance | New York Power Authority                  |       | Yes                       |
| Segment 5-2017-18 | Amy Casuscelli  
Sr. Reliability Standards Analyst | Xcel Energy                                |       | Yes                       |
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<td>Segment 6-2016-17</td>
<td>Andrew Gallo</td>
<td>City of Austin dba Austin Energy</td>
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<td>Director, Reliability Compliance</td>
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<td>Energy Future Holdings – Luminant Energy Company LLC</td>
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<td>Michael Marchand</td>
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<td>Guy Zito</td>
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<td>Western Electricity Coordinating Council</td>
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<td>Director of Standards</td>
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B. Murphy, chair, called to order the meeting of the Standards Committee (SC or the Committee) on May 1, 2017, at 4:00 p.m. Eastern. After the roll call by Secretary C. Larson, secretary, meeting quorum was declared. The SC member attendance and proxy sheet is attached hereto as Attachment 1.

**NERC Antitrust Compliance Guidelines and Public Announcement**
Committee secretary called attention to the NERC Antitrust Compliance Guidelines and the public meeting notice. He asked that any questions regarding the NERC Antitrust Compliance Guidelines be directed to NERC’s General Counsel, Charles Berardesco.

**Introduction and Chair's Remarks**
B. Murphy welcomed the Committee and guests.

**Review May 1, 2017 Agenda (agenda item 1)**
*Approved by unanimous consent.*

**Project 2016-03 Cyber Security Supply Chain Management (agenda item 2)**
S. Bodkin made a motion to accept the action item as written; G. Zito seconded. SC members requested the Implementation Guidance be referenced on the Project 2016-03 project page. B. Murphy brought the motion to a vote. The motion was as follows:

Authorize posting proposed Reliability Standards CIP-005-6 and CIP-010-3, the associated Implementation Plan, Violation Risk Factors (VRFs), and Violation Severity Levels (VSLs) for 45-day formal comment period with parallel initial ballots and nonbinding polls during the last 10 days of the comment period.

*The Committee approved the motion with no objections or abstentions.*

**Adjourn**
B. Murphy thanked the Committee members and adjourned the meeting at 4:34 p.m. Eastern.
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<td>Brian Murphy</td>
<td>NextEra Energy, Inc.</td>
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<td>Vice-Chair 2016-17</td>
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<td>Laura Lee</td>
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Senior Manager, Consulting | Siemens Power Technologies International | Yes |  |
| Segment 7-2017-18 | VACANT | | N/A |  |
| Segment 8-2016-17 | Robert Blohm  
Managing Director | Keen Resources Ltd. | Yes |  |
| Segment 8-2017-18 | David Kiguel | Independent | No |  |
| Segment 9-2016-17 | Alexander Vedvik  
Senior Electrical Engineer | Public Service Commission of Wisconsin | Yes |  |
| Segment 9-2017-18 | Michael Marchand  
Senior Policy Analyst | Arkansas Public Service Commission | Yes |  |
| Segment 10-2016-17 | Guy Zito  
Assistant Vice President of Standards | Northeast Power Coordinating Council | Yes |  |
| Segment 10-2017-18 | Steven Rueckert  
Director of Standards | Western Electricity Coordinating Council | Yes |  |
Action
Endorse the selection of Amy Casuscelli of Xcel Energy as vice chair of the Project Management and Oversight Subcommittee (PMOS) to complete the current term and a new two-year term starting December 2017.

Background
Ms. Casuscelli has been a member of PMOS and is also a member of the Standards Committee. PMOS selected Ms. Casuscelli to be its vice chair as set forth in the action item. With this action she will fill the remainder of the previous vice chair’s term.
Three-Month Outlook

Brian Murphy, SC Chair, NextEra Energy Resources, LLC
Steven Noess, Director of Standards Development, NERC
Standards Committee
June 5, 2017
Authorize Nomination Solicitations

• June
  ▪ Project 2017-01 Modifications to BAL-003-1.1

• July
  ▪ None

• August
  ▪ None
Authorize Team Appointments

• June
  ▪ Project 2017-06 Modifications to BAL-002-2*
  ▪ Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards PER-003-1, PER-004-2**

• July
  ▪ Project 2017-01 Modifications to BAL-003-1.1
  ▪ Project 2017-03 FAC-008 Periodic Review
  ▪ Project 2017-04 INT-004, INT-006, INT-009, and INT-010 Periodic Review
  ▪ Project 2017-05 NUC-001-3 Periodic Review

• August
  ▪ None

*Appoint the Project 2010-14.1 drafting team as the drafting team for the SAR or solicit SAR drafting team members.

**Appoint the EPR team as the SAR and standard drafting team.
Authorize SAR Postings

- June
  - Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards PER-003-1, PER-004-2
  - Project 2017-06 Modifications to BAL-002-2
  - Project 2017-01 Modifications to BAL-003-1.1
- July
  - None
- August
  - None
• June
  ▪ Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2

• July
  ▪ Project 2015-09 Establish and Communicate System Operating Limits FAC-010, FAC-011, FAC-014
  ▪ Project 2015-10 Single Points of Failure TPL-001-4
  ▪ Project 2016-02 Modifications to CIP Standards
  ▪ Project 2016-04 Modifications to PRC-025-1

• August
  ▪ None
FERC Orders and NOPRs

• April
  ▪ Letter Order Approving Reliability Standards IRO-002-5 and TOP-001-4
  ▪ Letter Order Approving Regional Reliability Standard VAR-501-WECC-3

• May
  ▪ Letter Order Approving Revisions to Texas RE Bylaws and Regional Reliability Standards Development Process

• June
  ▪ None
Questions and Answers
Project 2013-03 Geomagnetic Disturbance Mitigation

**Action**
Authorize posting proposed Reliability Standard TPL-007-2, the associated Implementation Plan, Violation Risk Factors (VRFs), and Violation Severity Levels (VSLs) for a 45-day formal comment period with parallel initial ballot and nonbinding poll during the last 10 days of the comment period.

**Background**
On September 22, 2016, FERC issued [Order No. 830](#) approving Reliability Standard TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance (GMD) Events. In the order, FERC directed NERC to develop certain modifications to the Standard, including:

- Modify the benchmark GMD event definition used for GMD Vulnerability Assessments;
- Make related modifications to requirements pertaining to transformer thermal impact assessments;
- Require collection of GMD-related data, which can be used for model validation and situational awareness; and
- Require deadlines for Corrective Action Plans and GMD mitigating actions.

FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

The standard drafting team (SDT) developed the revisions in proposed TPL-007-2 to address the above directives. The SDT discussed the draft Reliability Standard and Implementation Plan with the NERC GMD Task Force prior to finalizing for initial posting. The SDT is also completing the *Supplemental GMD Event Description* white paper, which provides technical justification for the new GMD event that applicable entities will use in addition to the approved benchmark GMD event in performing GMD Vulnerability Assessments. The magnitude of the new GMD event is between 14-17 V/km; its specific value will be finalized in the *Supplemental GMD Event Description* white paper and reflected in Attachment 1 to TPL-007-2 prior to posting. This white paper and two revised white papers from the TPL-007-1 project (*Transformer Thermal Impact Assessment* and *Thermal Screening Criterion*) will also be included in the initial posting for TPL-007-2.

Quality Review (QR) for this posting was performed by individuals from the Standards Committee, industry, and NERC staff. The QR summary is attached. The SDT considered all QR inputs and revised the proposed standard where appropriate.
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

<table>
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<tr>
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<tr>
<td>Standards Committee approved Standard Authorization Request (SAR) for posting</td>
<td>December 14, 2016</td>
</tr>
<tr>
<td>SAR posted for comment</td>
<td>December 16, 2016 – January 20, 2017</td>
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<tr>
<td>45-day formal comment period with ballot</td>
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<tr>
<td>45-day formal comment period with additional ballot</td>
<td>September 2017</td>
</tr>
<tr>
<td>10-day final ballot</td>
<td>TBD</td>
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<tr>
<td>Board adoption</td>
<td>February 2018</td>
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</table>
New or Modified Term(s) Used in NERC Reliability Standards

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

**Term(s):**

None
Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

**A. Introduction**

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events
2. **Number:** TPL-007-2
3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. **Applicability:**
   4.1. **Functional Entities:**
      4.1.1. Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
      4.1.2. Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
      4.1.3. Transmission Owner who owns a Facility or Facilities specified in 4.2;
      4.1.4. Generator Owner who owns a Facility or Facilities specified in 4.2.
   4.2. **Facilities:**
      4.2.1. Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.
5. **Effective Date:** See Implementation Plan for TPL-007-1
6. **Background:**
   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

**B. Requirements and Measures**

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements,
copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the
performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the
Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

**M5.** Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective benchmark GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

**R6.** Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. Be based on the effective GIC flow information provided in Requirement R5;
6.2. Document assumptions used in the analysis;
6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

**M6.** Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

**Rationale for Requirement R7:** The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P. 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P. 102):
R7. Each responsible entity, as determined in Requirement R1, that concludes through the benchmark GMD Vulnerability Assessment conducted in Requirement R4 that their System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The CAP shall:

[Violation Risk Factor: High]  [Time Horizon: Long-term Planning]

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;
7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

7.5. Be provided: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.5.1. If a recipient of the CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity’s System does not meet the performance requirements for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity’s control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its CAP or relevant information, if any, (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.
Supplemental GMD Vulnerability Assessment(s)

Rationale for Requirements R8 - R10: The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P.44, P47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and
8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2. The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3. If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4. The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1. If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment
meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: "Violation Risk Factor: Medium" [Time Horizon: Long-term Planning]

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective supplemental GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power
transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

10.1. Be based on the effective GIC flow information provided in Requirement R9;
10.2. Document assumptions used in the analysis;
10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

GMD Measurement Data Processes

**Rationale for Requirements R11 and R12:** The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P. 88; P. 90-92). See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 6 of the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities.
- Installed magnetometers
Commercial or third-party sources of geomagnetic field data

Geomagnetic field data for a Planning Coordinator’s planning area is obtained from one or more of the above data sources located in the Planning Coordinator’s planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator’s planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator’s planning area.

**R11.** Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator’s planning area or other part of the system included in the Planning Coordinator's GIC System model. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

**M11.** Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

**R12.** Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator’s planning area. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

**M12.** Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator’s planning area in accordance with Requirement R12.

**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.

- For Requirements R1, R2, R3, R5, R6, R9, and R10, each responsible entity shall retain documentation as evidence for five years.
- For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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.
### Table 1 – Steady State Planning GMD Event

**Steady State:**

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the steady state planning GMD events.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

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<th>Initial Condition</th>
<th>Event</th>
<th>Interruption of Firm Transmission Service Allowed</th>
<th>Load Loss Allowed</th>
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<tr>
<td><strong>Benchmark GMD Event - GMD Event with Outages</strong></td>
<td>1. System as may be postured in response to space weather information(^1), and then 2. GMD event(^2)</td>
<td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td>
<td>Yes(^3)</td>
<td>Yes(^3)</td>
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<tr>
<td><strong>Supplemental GMD Event - GMD Event with Outages</strong></td>
<td>1. System as may be postured in response to space weather information(^1), and then 2. GMD event(^2)</td>
<td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td>
<td>Yes</td>
<td>Yes</td>
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### Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.

2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1.

3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.
### Violation Severity Levels

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<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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<tr>
<td>R1.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.</td>
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<tr>
<td>R2.</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity did not maintain either System models or GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.</td>
<td>The responsible entity did not maintain both System models and GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in this standard.</td>
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<td>studies needed to complete benchmark and supplemental GMD Vulnerability Assessments.</td>
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<td>R3.</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the GMD events described in Attachment 1 as required.</td>
<td></td>
</tr>
<tr>
<td>R4.</td>
<td>The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.</td>
<td>The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.</td>
<td>The responsible entity's completed benchmark GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR</td>
<td></td>
</tr>
<tr>
<td>Requirement</td>
<td>Description</td>
<td>Description</td>
<td>Description</td>
<td>Description</td>
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<td>-------------</td>
<td>-------------</td>
</tr>
<tr>
<td>R5.</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.</td>
<td>The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.</td>
</tr>
<tr>
<td>R6.</td>
<td>The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase;</td>
<td>The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5,</td>
<td>The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in</td>
<td>The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5,</td>
</tr>
</tbody>
</table>
| **OR** | **Part 5.1, is 75 A or greater per phase;**  
| **The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.**  
| **Requirement R5, Part 5.1, is 75 A or greater per phase;**  
| **The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;**  
| **The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.**  
| **Part 5.1, is 75 A or greater per phase;**  
| **The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;**  
| **The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.**  
| **Part 5.1, is 75 A or greater per phase;**  
| **The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;**  
| **The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.**  
| **Part 5.1, is 75 A or greater per phase;**  
| **The responsible entity conducted a benchmark thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1;**  
| **The responsible entity failed to include four or more of the required elements in**  

### R7.

- The responsible entity's Corrective Action Plan failed to comply with one of the elements in Requirement R7, Parts 7.1 through 7.5.
- The responsible entity's Corrective Action Plan failed to comply with two of the elements in Requirement R7, Parts 7.1 through 7.5.
- The responsible entity's Corrective Action Plan failed to comply with three of the elements in Requirement R7, Parts 7.1 through 7.5.
- The responsible entity's Corrective Action Plan failed to comply with four or more of the elements in Requirement R7, Parts 7.1 through 7.5.
<table>
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<th>Requirement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>R7</td>
<td>Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.</td>
</tr>
<tr>
<td>R8</td>
<td>The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.</td>
</tr>
<tr>
<td>R9.</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.</td>
</tr>
<tr>
<td>R10.</td>
<td>The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment</td>
</tr>
</tbody>
</table>
for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.

thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.

thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.

The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator’s planning area or other part of the system included in the Planning Coordinator’s GIC System Model.
R12. | N/A | N/A | N/A | The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator’s planning area.

**D. Regional Variances**
None.

**E. Associated Documents**
None.
## Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
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<td>1</td>
<td>December 17, 2014</td>
<td>Adopted by the NERC Board of Trustees</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>TBD</td>
<td>Revised to respond to directives in FERC Order No. 830.</td>
<td>Revised</td>
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</table>
Standard Attachments
The following attachments are part of TPL-007-2.
Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Events

The benchmark GMD event\(^1\) defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 17 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.\(^2\)

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, \(E_{\text{peak}}\), can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 17 V/km for the supplemental GMD event (2) using the following relationship

\[
E_{\text{peak}} = 8 \times \alpha \times \beta_b \text{ (V/km)}
\]

\[
E_{\text{peak}} = 17 \times \alpha \times \beta_s \text{ (V/km)}
\]

where \(\alpha\) is the scaling factor to account for local geomagnetic latitude, and \(\beta\) is a scaling factor to account for the local earth conductivity structure. Subscripts \(b\) and \(s\) for the \(\beta\) scaling factor denote association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD events are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor \(\alpha\) is computed with the empirical expression

\[
\alpha = 0.001 \cdot e^{(0.115-L)}
\]

where \(L\) is the geomagnetic latitude in degrees and \(0.1 \leq \alpha \leq 1.0\).

---

\(^1\) The benchmark GMD event description is available on the Related Information page for TPL-007-1:
http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

\(^2\) The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The amplitude of the resulting geoelectric field is on the order of twice the geoelectric field that is calculated in the spatially-averaged Benchmark GMD event. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental GMD Event Description white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx
For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for $\alpha$; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

<table>
<thead>
<tr>
<th>Geomagnetic Latitude (Degrees)</th>
<th>Scaling Factor1 ($\alpha$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\leq 40$</td>
<td>0.10</td>
</tr>
<tr>
<td>$45$</td>
<td>0.2</td>
</tr>
<tr>
<td>$50$</td>
<td>0.3</td>
</tr>
<tr>
<td>$54$</td>
<td>0.5</td>
</tr>
<tr>
<td>$56$</td>
<td>0.6</td>
</tr>
<tr>
<td>$57$</td>
<td>0.7</td>
</tr>
<tr>
<td>$58$</td>
<td>0.8</td>
</tr>
<tr>
<td>$59$</td>
<td>0.9</td>
</tr>
<tr>
<td>$\geq 60$</td>
<td>1.0</td>
</tr>
</tbody>
</table>

**Scaling the Geoelectric Field**

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, $E_{\text{peak}}$, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;\(^3\) or
- Using the earth conductivity scaling factor $\beta$ from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor $\alpha$ from equation (3) or Table 2, $\beta$ is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude $E_{\text{peak}}$ to be used in GMD Vulnerability Assessments. When a ground conductivity model is not available, the planning entity should use the largest $\beta$ factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.\(^4\) The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect

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\(^3\) Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

\(^4\) Available at http://geomag.usgs.gov/conductivity/
the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the $\beta$ factor(s) as follows:

$$\beta_b = E / 8 \quad \text{for the benchmark GMD event} \quad (4)$$

$$\beta_s = E / 17 \quad \text{for the supplemental GMD event} \quad (5)$$

where $E$ is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one $\beta$ scaling factor, the most conservative (largest) value for $\beta$ may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

### Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.\(^5\) Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (17 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (17 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

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\(^5\) See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: [http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx](http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx)
Figure 1: Physiographic Regions of the Continental United States\textsuperscript{6}

Figure 2: Physiographic Regions of Canada

\textsuperscript{6} Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)
### Table 3 – Geoelectric Field Scaling Factors

<table>
<thead>
<tr>
<th>USGS Earth model</th>
<th>Scaling Factor Benchmark Event ($\beta_{b}$)</th>
<th>Scaling Factor Supplemental Event ($\beta_{s}$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AK1A</td>
<td>0.56</td>
<td>0.48</td>
</tr>
<tr>
<td>AK1B</td>
<td>0.56</td>
<td>0.48</td>
</tr>
<tr>
<td>AP1</td>
<td>0.33</td>
<td>0.28</td>
</tr>
<tr>
<td>AP2</td>
<td>0.82</td>
<td>0.76</td>
</tr>
<tr>
<td>BR1</td>
<td>0.22</td>
<td>0.22</td>
</tr>
<tr>
<td>CL1</td>
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<td>0.71</td>
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<tr>
<td>CO1</td>
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<td>0.25</td>
</tr>
<tr>
<td>CP1</td>
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<td>0.80</td>
</tr>
<tr>
<td>CP2</td>
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<td>0.91</td>
</tr>
<tr>
<td>FL1</td>
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<td>0.74</td>
</tr>
<tr>
<td>CS1</td>
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<td>0.35</td>
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<tr>
<td>IP1</td>
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<td>0.89</td>
</tr>
<tr>
<td>IP2</td>
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<td>0.24</td>
</tr>
<tr>
<td>IP3</td>
<td>0.93</td>
<td>0.88</td>
</tr>
<tr>
<td>IP4</td>
<td>0.41</td>
<td>0.33</td>
</tr>
<tr>
<td>NE1</td>
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<td>0.74</td>
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<tr>
<td>PB1</td>
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<td>0.51</td>
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<tr>
<td>PB2</td>
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<td>1.19</td>
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<td>SL1</td>
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<td>SU1</td>
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<td>0.88</td>
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<tr>
<td>BOU</td>
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<tr>
<td>FBK</td>
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<td>PRU</td>
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<td>PRAIRIES</td>
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<tr>
<td>SHIELD</td>
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<tr>
<td>ATLANTIC</td>
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### Table 4 – Reference Earth Model (Quebec)

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<th>Layer Thickness (km)</th>
<th>Resistivity (Ω-m)</th>
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</thead>
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<tr>
<td>15</td>
<td>20,000</td>
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<td>10</td>
<td>200</td>
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<tr>
<td>125</td>
<td>1,000</td>
</tr>
<tr>
<td>200</td>
<td>100</td>
</tr>
<tr>
<td>$\infty$</td>
<td>3</td>
</tr>
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</table>
Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds. To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor βb.

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7 Refer to the Benchmark GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: [http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx](http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx)

8 The data file of the benchmark geomagnetic field waveform is available on the Related Information page for TPL-007-1: [http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx](http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx)
Figure 3: Benchmark Geomagnetic Field Waveform. Red $B_n$ (Northward), Blue $B_e$ (Eastward)

Figure 4: Benchmark Geoelectric Field Waveform - $E_e$ (Eastward)
Figure 5: Benchmark Geoelectric Field Waveform – $E_N$ (Northward)
Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitudes of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 17 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds. To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor βs.

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9 Refer to the Supplemental GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

10 The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx
Figure 6: Supplemental Geomagnetic Field Waveform. Red $B_n$ (Northward), Blue $B_e$ (Eastward)

Figure 7: Supplemental Geoelectric Field Waveform. Red $E_n$ (Northward), Blue $E_e$ (Eastward)
Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:

The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)
The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page at:
http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

Supplemental GMD Event (Attachment 1)
The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. A white paper that includes the event description and analysis is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not
enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

**Requirement R4**

**Requirement R5**
The benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady state GIC flows to time-series GIC data for the benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

**Requirement R6**
The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper. The ERO enterprise has endorsed the white paper as Implementation Guidance for this requirement. The white paper is posted on the NERC compliance guidance page:

[http://www.nerc.com/pa/comp/guidance/Pages/default.aspx](http://www.nerc.com/pa/comp/guidance/Pages/default.aspx)

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the TPL-007-1 Related Information page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

**Requirement R7**

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the 2012 *Special Reliability Assessment Interim Report: Effects ofGeomagnetic Disturbances on the Bulk-Power System*:


**Requirement R8**

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:


The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

**Requirement R9**

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.
The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

**Requirement R10**

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper discussed in the Requirement R6 section above. A revised version of the Transformer Thermal Impact Assessment white paper has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment. This revised white paper is posted on the project page at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

**Requirement R11**

Technical considerations for GIC monitoring are contained in the NERC 2012 GMD Report (see Chapter 6). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC
based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g. subways or light rail) may be unreliable.

- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow (Positive reference is flow from ground into transformer neutral). Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

**Requirement R12**
Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations ([http://www.intermagnet.org/](http://www.intermagnet.org/)):
• Research institutions and academic universities;
• Entities with installed magnetometers.
Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual, which is available at: http://www.intermagnet.org/publications/intermag_4-6.pdf

Rationale
During development of TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. The text from the rationale text boxes was moved to this section upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [  ].

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.
The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

**Rationale for R3:**
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

**Rationale for R4:**
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:


The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

**Rationale for R5:**
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

[http://www.nerc.com/pa/comp/guidance/Pages/default.aspx]

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but
no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

**Rationale for R6:**
The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

**Rationale for R7:**
Corrective Action Plans are defined in the NERC Glossary of Terms:

> A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force GMD Planning Guide provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3 [Part 7.5 in TPL-007-2], shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.
Rationale for Table 3:
Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74 [for the benchmark GMD event].
A. Introduction

1. Title: Transmission System Planned Performance for Geomagnetic Disturbance Events
2. Number: TPL-007-12
3. Purpose: Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.
4. Applicability:
   4.1. Functional Entities:
      4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;
      4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;
      4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;
      4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.
   4.2. Facilities:
      4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. Background:
   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

6. Effective Date:
   See Implementation Plan for TPL-007-12

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models and performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s), and implementing process(es) to obtain GMD measurement data as specified in this standard. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models and.
performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s), and implementing process(es) to obtain GMD Measurement Data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s). [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s).

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event(s) described in Attachment 1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

**Benchmark GMD Vulnerability Assessment(s)**

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) within 90 calendar days of completion to the responsible entity’s Reliability Coordinator,
adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the transformer benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power...
transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective benchmark GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1. Be based on the effective GIC flow information provided in Requirement R5;

6.2. Document assumptions used in the analysis;

6.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

6.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R7: The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P. 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P. 102):

• Two years for non-hardware mitigation; and
The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3.

R7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that their System does not meet the performance requirements of the steady state planning benchmark GMD event contained in Table 1 shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The Corrective Action Plan (CAP) shall:

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
   - Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
   - Installation, modification, or removal of Protection Systems or Special Protection Systems Remedial Action Schemes.
   - Use of Operating Procedures, specifying how long they will be needed as part of the Corrective Action Plan (CAP).
   - Use of Demand-Side Management, new technologies, or other initiatives.

7.2. Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1. Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:
   - Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and
   - Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:
   - Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;
7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

7.2.7.5. Be provided: (i) within 90 calendar days of completion development or revision to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the Corrective Action Plan CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

7.2.1.7.5.1. If a recipient of the Corrective Action Plan CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements of the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its Corrective Action Plan CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its Corrective Action Plan CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later, within 90 calendar days of its completion development or revision to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan CAP, and any functional entity that submits a written request and has a reliability-related need, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date,
that it has provided a documented response to comments received on its Corrective Action Plan (CAP) within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

**Supplemental GMD Vulnerability Assessment(s)**

**Rationale for Requirements R8 - R10:** The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P.44, P.47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

**R8.** Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2 The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3 If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4 The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1 If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity
shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity’s Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective supplemental GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal...
receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

**R10.** Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

  10.1. Be based on the effective GIC flow information provided in Requirement R9;
  10.2. Document assumptions used in the analysis;
  10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
  10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

**M10.** Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

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**GMD Measurement Data Processes**

**Rationale for Requirements R11 and R12:** The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P. 88; P. 90-92). See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator’s planning area or other part of the system included in the Planning Coordinator’s GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 6 of the 2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System (NERC 2012 GMD Report). GIC monitoring is generally performed...
by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator’s planning area to inform GMD Vulnerability Assessments. Magnetometers provide geomagnetic field data by measuring changes in the earth’s magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities.
- Installed magnetometers
- Commercial or third-party sources of geomagnetic field data

Geomagnetic field data for a Planning Coordinator’s planning area is obtained from one or more of the above data sources located in the Planning Coordinator’s planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator’s planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator’s planning area.

R8.R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator’s planning area or other part of the system included in the Planning Coordinator’s GIC System model. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

R9.R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator’s planning area. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator’s planning area in accordance with Requirement R12.
### Table 1 – Steady State Planning GMD Event

**Steady State:**

- a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.
- b. Generation loss is acceptable as a consequence of the steady state planning GMD events.
- c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event</th>
<th>Interruption of Firm Transmission Service Allowed</th>
<th>Load Loss Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benchmark GMD Event</strong> - GMD Event with Outages</td>
<td>1. System as may be postured in response to space weather information(^1), and then 2. GMD event(^2)</td>
<td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td>
<td>Yes(^3)</td>
<td>Yes(^3)</td>
</tr>
<tr>
<td><strong>Supplemental GMD Event</strong> - GMD Event with Outages</td>
<td>1. System as may be postured in response to space weather information(^1), and then 2. GMD event(^2)</td>
<td>Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event</td>
<td>Yes(^2)</td>
<td>Yes(^2)</td>
</tr>
</tbody>
</table>

### Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning events are described in Attachment 1 (Benchmark GMD Event).
3. Load loss as a result of manual or automatic Load shedding (e.g., UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.
Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD Event

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 17 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, $E_{\text{peak}}$, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event or 17 V/km for the supplemental GMD event using the following relationship

$$ E_{\text{peak}} = 8 \times \alpha \times \beta_b \ (V/km) \quad (1) $$

$$ E_{\text{peak}} = 17 \times \alpha \times \beta_s \ (V/km) \quad (2) $$

where $\alpha$ is the scaling factor to account for local geomagnetic latitude, and $\beta$ is a scaling factor to account for the local earth conductivity structure. Subscripts $b$ and $s$ for the $\beta$ scaling factor denotes association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD event definitions are defined for geomagnetic latitude of 60° and must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor $\alpha$ is computed with the empirical expression

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1 The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

2 The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The amplitude of the resulting geoelectric field is on the order of twice the geoelectric field that is calculated in the spatially-averaged Benchmark GMD event. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the Supplemental GMD Event Description white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx
where $L$ is the geomagnetic latitude in degrees and $0.1 \leq \alpha \leq 1$.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:
- calculated by using the most conservative (largest) value for $\alpha$; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

### Table 2—Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

<table>
<thead>
<tr>
<th>Geomagnetic Latitude (Degrees)</th>
<th>Scaling Factor1 ($\alpha$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\leq 40$</td>
<td>0.10</td>
</tr>
<tr>
<td>45</td>
<td>0.2</td>
</tr>
<tr>
<td>50</td>
<td>0.3</td>
</tr>
<tr>
<td>54</td>
<td>0.5</td>
</tr>
<tr>
<td>56</td>
<td>0.6</td>
</tr>
<tr>
<td>57</td>
<td>0.7</td>
</tr>
<tr>
<td>58</td>
<td>0.8</td>
</tr>
<tr>
<td>59</td>
<td>0.9</td>
</tr>
<tr>
<td>$\geq 60$</td>
<td>1.0</td>
</tr>
</tbody>
</table>

### Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, $E_{\text{peak}}$, used in a GMD Vulnerability Assessment may be obtained by either

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;\(^3\) or
- Using the earth conductivity scaling factor $\beta$ from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor $\alpha$ from equation (2) or Table 2, $\beta$ is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude $E_{\text{peak}}$ to be used in GMD Vulnerability Assessment. When a ground conductivity model is not

\(^3\) Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx
available, the planning entity should use the largest $\beta$ factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.4 The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the $\beta$ factor(s) as follows:

$$\beta_b = \frac{E}{8\beta_b} \text{ for the benchmark GMD event}$$
$$\beta_s = \frac{E}{17} \text{ for the supplemental GMD event}$$

where $E$ is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one $\beta$ scaling factor, the most conservative (largest) value for $\beta$ may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

**Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event**

The peak geoelectric field of the supplemental GMD event occurs in a localized area.5 Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (17 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (17 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

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4 Available at http://geomag.usgs.gov/conductivity/

5 See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx
Figure 1: Physiographic Regions of the Continental United States

Figure 2: Physiographic Regions of Canada

* Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)
<table>
<thead>
<tr>
<th>USGS Earth model</th>
<th>Scaling Factor Benchmark Event ($\beta_b$)</th>
<th>Scaling Factor Supplemental Event ($\beta_s$)</th>
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<tr>
<td>AK1A</td>
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<td>0.48</td>
</tr>
<tr>
<td>AK1B</td>
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<tr>
<td>AP1</td>
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<td>0.74</td>
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<table>
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<th>Layer Thickness (km)</th>
<th>Resistivity (Ω-m)</th>
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<td>15</td>
<td>20,000</td>
</tr>
<tr>
<td>10</td>
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<tr>
<td>125</td>
<td>1,000</td>
</tr>
<tr>
<td>200</td>
<td>100</td>
</tr>
<tr>
<td>∞</td>
<td>3</td>
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</table>
Reference Geomagnetic Field Time Series or Waveform for the Benchmark GMD Event

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The sampling rate for the geomagnetic field waveform is 10 seconds. To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor $\beta$.

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7 Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

8 Refer to the Benchmark GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

Figure 3: Benchmark Geomagnetic Field *Waveform*. Red B_n (Northward), Blue B_e (Eastward)

Figure 4: Benchmark Geoelectric Field *Waveform* - E_e (Eastward)
Figure 5: Benchmark Geoelectric Field Waveform – $E_n$ (Northward)
Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at NRCan’s Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 17 V/km (see Figure 7). The sampling rate for the geomagnetic field waveform is 10 seconds. To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor βs.

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10 Refer to the Supplemental GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

11 The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx
Figure 6: Supplemental Geomagnetic Field Waveform. Red $B_n$ (Northward), Blue $B_e$ (Eastward)

Figure 7: Supplemental Geoelectric Field Waveform. Red $E_n$ (Northward), Blue $E_e$ (Eastward)
C. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

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

   1.2. Evidence Retention

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

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

       • For Requirements R1, R2, R3, R5, R6, R9, and R6R10, each responsible entity shall retain documentation as evidence for five years.
       • For Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
       • For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
       • For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information
None
• For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

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

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>Long-term Planning</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator’s planning area for maintaining models and, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s), and implementing process(es) to obtain</td>
</tr>
<tr>
<td>R2</td>
<td>Long-term Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity did not maintain either System models or GIC System models of the responsible entity’s planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s). The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment(s).</td>
<td></td>
</tr>
<tr>
<td>R3</td>
<td>Long-term Planning</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the benchmark GMD event events described in Attachment 1 as required.</td>
</tr>
<tr>
<td>R4</td>
<td>Long-term Planning</td>
<td>High</td>
<td>The responsible entity completed a benchmark GMD</td>
<td>The responsible entity’s completed benchmark GMD</td>
<td>The responsible entity’s completed benchmark GMD</td>
<td>The responsible entity’s completed benchmark GMD</td>
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<tr>
<td>R5</td>
<td><strong>Long-term Planning</strong></td>
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<td>---</td>
<td>---</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Vulnerability Assessment, but it was more than 60 calendar months</strong> and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.</td>
<td><strong>Vulnerability Assessment failed to satisfy one of the elements listed in Requirement R4, Parts 4.1 through 4.3;</strong>&lt;br&gt;The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.</td>
<td><strong>Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3;</strong>&lt;br&gt;The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| **Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3;**<br>The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; | **OR**<br>The responsible entity does not have a completed benchmark GMD Vulnerability Assessment. | **OR**<br>The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each
<table>
<thead>
<tr>
<th>R6</th>
<th>Long-term Planning</th>
<th>Medium</th>
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<tbody>
<tr>
<td></td>
<td>The responsible entity failed to conduct a <strong>benchmark</strong> thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a <strong>benchmark</strong> thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a <strong>benchmark</strong> thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a <strong>benchmark</strong> thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a <strong>benchmark</strong> thermal impact assessment for more than 30% or more than five of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a <strong>benchmark</strong> thermal impact assessment for more than 50% or more than ten of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase.</td>
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<td>in Requirement R5, Part 5.1, is 75 A or greater per phase but</td>
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<td>did so more than 24 calendar months and less than or equal to</td>
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<td>26 calendar months of receiving GIC flow information specified</td>
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<td>in Requirement R5, Part 5.1.</td>
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<td>Impact assessment for its solely owned and jointly owned</td>
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<td>applicable BES power transformers where the maximum effective</td>
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<td>GIC value provided in Requirement R5, Part 5.1, is 75 A or</td>
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<td>greater per phase but did so more than 26 calendar months and</td>
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<td>less than or equal to 28 calendar months of receiving GIC flow</td>
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<td>information specified in Requirement R5, Part 5.1; OR</td>
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<td>The responsible entity failed to include one of the required</td>
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<td>elements as listed in Requirement R6, Parts 6.1 through 6.3.</td>
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<td>less than or equal to 30 calendar months of receiving GIC flow</td>
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<td>information specified in Requirement R5, Part 5.1; OR</td>
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<td>GIC value provided in Requirement R5, Part 5.1, is 75 A or</td>
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<td>greater per phase but did so more than 30 calendar months of</td>
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<td>receiving GIC flow information specified in Requirement R5,</td>
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<td>Part 5.1; OR</td>
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<td>The responsible entity failed to include four or more of the</td>
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<td>elements as listed in Requirement R6, Parts 6.1 through 6.3.</td>
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<td>The responsible entity’s Corrective Action Plan failed to</td>
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<td>comply with one of the elements in</td>
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<td>The responsible entity’s Corrective Action Plan failed to</td>
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<td>comply with four or more of the elements.</td>
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<td>Requirement R7, Parts 7.1 through 7.5</td>
<td>Requirement R7, Parts 7.1 through 7.5</td>
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<tr>
<td><strong>R8</strong></td>
<td><strong>The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment:</strong> OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment.</td>
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<tr>
<td>R9</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.</td>
<td>The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.</td>
</tr>
<tr>
<td>R10</td>
<td>The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power</td>
<td>The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned</td>
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</table>
| transformers owned applicable BES owned applicable BES applicable BES power transformers (whichever is greater) power transformers (whichever is greater) power transformers (whichever is greater) where the maximum where the maximum where the maximum effective GIC value effective GIC value effective GIC value provided in provided in provided in Requirement R9, Part Requirement R9, Part Requirement R9, Part 9.1, is 85 A or greater 9.1, is 85 A or greater 9.1, is 85 A or greater per phase; per phase; per phase; OR The responsible entity OR The responsible entity OR The responsible entity conducted a conducted a conducted a supplemental thermal supplemental thermal supplemental thermal impact assessment for impact assessment for impact assessment for its solely owned and its solely owned and its solely owned and jointly owned jointly owned jointly owned applicable BES power applicable BES power applicable BES power transformers where transformers where transformers where the maximum the maximum the maximum effective GIC value effective GIC value effective GIC value provided in provided in provided in Requirement R9, Part Requirement R9, Part Requirement R9, Part 9.1, is 85 A or greater 9.1, is 85 A or greater 9.1, is 85 A or greater per phase but did so per phase but did so per phase but did so more than 24 calendar more than 26 calendar more than 28 calendar months and less than months and less than months and less than or equal to 26 or equal to 28 or equal to 30 calendar calendar calendar months of months of months of receiving GIC flow receiving GIC flow receiving GIC flow information specified information specified information specified in Requirement R9, in Requirement R9, in Requirement R9, Part 9.1. Part 9.1. Part 9.1.; OR

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<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
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<tbody>
<tr>
<td>R11</td>
<td>The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator’s planning area or other part of the system included in the Planning Coordinator’s GIC System Model.</td>
</tr>
<tr>
<td>R12</td>
<td>The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator’s planning area.</td>
</tr>
</tbody>
</table>
D. Regional Variances
None.

E. Interpretations
None.

F. Associated Documents
None.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>December 17, 2014</td>
<td>Adopted by the NERC Board of Trustees</td>
<td></td>
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<tr>
<td>2</td>
<td>TBD</td>
<td>Revised to respond to directives in FERC Order No. 830.</td>
<td>Revised</td>
</tr>
</tbody>
</table>
The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)
The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Supplemental GMD Event (Attachment 1)
The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. A white paper that includes the event description and analysis is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System. The guide is available at:

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The diagram below provides an overall view of the GMD Vulnerability Assessment process:

Requirement R5
The transformer benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the Benchmark benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady-state GIC flows to time-series GIC data for transformer benchmark thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment.
assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page. The ERO enterprise has endorsed the white paper as Implementation Guidance for this requirement. The white paper is posted on the NERC compliance guidance page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project TPL-007-1 Related Information page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7


Requirement R8


The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.
Application Guidelines

**Requirement R9**
The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

**Requirement R10**
The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper discussed in the Requirement R6 section above. A revised version of the Transformer Thermal Impact Assessment white paper has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment. This revised white paper is posted on the project page at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised Screening Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

**Requirement R11**
Application Guidelines

Technical considerations for GIC monitoring are contained in the NERC 2012 GMD Report (see Chapter 6). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g. subways or light rail) may be unreliable.

- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through +500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.

- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.

- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.

- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) [MM/DD/YYYY HH:MM:SS] and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow (Positive reference is flow from ground into transformer neutral). Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.

- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

**Requirement R12**

Magnetometers measure changes in the earth’s magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:
Application Guidelines

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations (http://www.intermagnet.org/):

- Research institutions and academic universities:
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual, which is available at: http://www.intermagnet.org/publications/intermag_4-6.pdf
Application Guidelines

Rationale:
During development of this standard TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section. Upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [].

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.
**Rationale for R4:**
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:


The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

**Rationale for R5:**
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady-state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

**Rationale for R6:**
The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase. [for the benchmark GMD event]. Only those transformers that experience an
Application Guidelines

Effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:

A list of actions and an associated timetable for implementation to remedy a specific problem.

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the Benchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force GMD Planning Guide provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3: [Part 7.5 in TPL-007-2], shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for Table 3:
Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74—[for the benchmark GMD event].
Reliability Standard Quality Review Form

Project Name: 2013-03 Geomagnetic Disturbance Mitigation

Standard: TPL-007-2

Date of Review: May 24, 2017

The standard drafting team (SDT) conducted a quality review in accordance with the NERC Guideline for Quality Review of NERC Reliability Standards Project Documents and recommends that the Standards Committee authorize the proposed documents for formal posting and balloting.

Background
The NERC Standard Processes Manual (SPM) Section 4.6 requires NERC staff to coordinate a Quality Review\(^1\) of the Reliability Standard, Implementation Plan, Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), in parallel with the development of the Reliability Standard and Implementation Plan to assess whether:

1. The documents proposed for posting are within the scope of the associated Standard Authorization Request (SAR);
2. The Reliability Standard is clear and enforceable as written; and
3. The Reliability Standard meets the criteria specified in:
   a. NERC’s Benchmarks for Excellent Standards\(^2\)
   b. Criteria for governmental approval of Reliability Standards.\(^3\)

The drafting team considered the results of the quality review and decided upon appropriate changes.

Quality Review Summary
Reviewers provided written inputs that were considered by the standard drafting team (SDT) on May 24, 2017. The SDT accepted the recommended changes that improved the clarity of the proposed requirements. The review led to the following changes:

- Revised Requirements R1 and R2 to clarify the applicability to two types of Geomagnetic Disturbance (GMD) Vulnerability Assessments (benchmark and supplemental);
- Revised Requirements R4 and R8 to indicate assessments are to be performed \textit{at least} once every 60 calendar months;

\(^1\) The SPM’s Quality Review requirements also apply to new or revised definitions and Reliability Standard interpretations.


\(^3\) See FERC Order No. 672
• Clarified deadlines for distributing GMD Vulnerability Assessment information in Parts 4.3, 7.5, and 8.4;
• Made editorial revisions to Rationale sections, attachment, and supplemental material section for clarity and readability; and
• Made format corrections to the Implementation Plan.

After discussion, the SDT decided not to act on a reviewer’s concern that Requirements R11 and R12 could be interpreted as being strictly administrative. The reliability objective of Requirements R11 and R12 is to enable model validation as stated in Order No. 830 (P. 88) and cited in TPL-007-2 rationale and guidelines sections. The SDT has considered various approaches and believes Requirements R11 and R12 as written meet the directive and benefit reliability by providing entities with a flexible approach to obtaining data for validating GIC System Models or other models used in performing GMD Vulnerability Assessments. Development of technical guidance for model validation will provide additional reliability benefit, however, this is not in the SDT’s scope. (Guidance for model validation is part of the GMD work plan being developed by NERC and the GMD Task Force to meet Order No. 830 directives.)

Quality Review participants included:

• Guy Zito - NPCC
• Jennifer Sterling - Exelon
• Soo Jin Kim - NERC, Manager of Standards Development
• Lauren Perotti - NERC Legal
• Ed Kichline - NERC Compliance Enforcement
• Ryan Mauldin - NERC Compliance
• Nasheema Santos - NERC Standards

The SDT recommends that the Standards Committee authorize this project for initial comment and ballot period.
Frank Koza, Chair (reviewed/signed by email)     May 24, 2017
Drafting Team Leadership        Date
Implementation Plan
Project 2013-03 Geomagnetic Disturbance Mitigation
Reliability Standard TPL-007-2

Applicable Standard(s)
- TPL-007-2 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Requested Retirement(s)
- TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events

Prerequisite Standard(s)
None

Applicable Entities
- Planning Coordinator with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Planner with a planning area that includes a Facility or Facilities specified in Section 4.2 of the standard;
- Transmission Owner who owns a Facility or Facilities specified in Section 4.2 of the standard; and
- Generator Owner who owns a Facility or Facilities specified in Section 4.2 of the standard.

Section 4.2 states that the standard applies to facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

Terms in the NERC Glossary of Terms
There are no new, modified, or retired terms.

Background
On September 22, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 830 approving Reliability Standard TPL-007-1 and its associated five-year Implementation Plan. In the Order, FERC also directed NERC to develop certain modifications to the standard. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018.

General Considerations
This Implementation Plan is intended to integrate the new requirements in TPL-007-2 with the GMD Vulnerability Assessment process that is being implemented through approved TPL-007-1. At the
time of the May 2018 filing deadline, many requirements in approved standard TPL-007-1 that lead to completion of the GMD Vulnerability Assessment will be in effect. Furthermore, many entities may be taking steps to complete studies or assessments that are required by future enforceable requirements in TPL-007-1. The Implementation Plan phases in the requirements in TPL-007-2 based on the effective date of TPL-007-2, as follows:

- **Effective Date before January 1, 2021.** Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

- **Effective Date on or after January 1, 2021.** Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

**Effective Date and Phased-In Compliance Dates**
The effective date for the proposed Reliability Standard is provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (e.g., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

**Standard TPL-007-2**
Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is three months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

*If TPL-007-2 becomes effective before January 1, 2021*
Implementation timeline supports applicable entities completing new requirements for supplemental GMD Vulnerability Assessments concurrently with requirements for the benchmark GMD Vulnerability Assessment (concurrent effective dates).

**Compliance Date for TPL-007-2 Requirement R9**
Entities shall not be required to comply with Requirement R9 until six months after the effective date of Reliability Standard TPL-007-2.
Compliance Date for TPL-007-2 Requirements R11 and R12
Entities shall not be required to comply with Requirements R11 and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R6 and R10
Entities shall not be required to comply with Requirements R6 and R10 until 30 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R3, R4, and R8
Entities shall not be required to comply with Requirements R3, R4, and R8 until 42 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R7
Entities shall not be required to comply with Requirement R7 until 54 months after the effective date of Reliability Standard TPL-007-2.

*If TPL-007-2 becomes effective on or after January 1, 2021*
Implementation timeline supports applicable entities completing the benchmark GMD Vulnerability Assessments before new requirements for supplemental GMD Vulnerability Assessments become effective.

Compliance Date for TPL-007-2 Requirements R3 and R4
Entities shall not be required to comply with Requirements R3 and R4 until 12 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirements R7, R11, and R12
Entities shall not be required to comply with Requirements R7, R11, and R12 until 24 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R9
Entities shall not be required to comply with Requirement R9 until 36 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R10
Entities shall not be required to comply with Requirement R10 until 60 months after the effective date of Reliability Standard TPL-007-2.

Compliance Date for TPL-007-2 Requirement R8
Entities shall not be required to comply with Requirement R8 until 72 months after the effective date of Reliability Standard TPL-007-2.
Retirement Date
Standard TPL-007-1
Reliability Standard TPL-007-1 shall be retired immediately prior to the effective date of TPL-007-2 in the particular jurisdiction in which the revised standard is becoming effective.

Initial Performance of Periodic Requirements
Transmission Owners and Generator Owners are not required to comply with Requirement R6 prior to the compliance date for Requirement R6, regardless of when geomagnetically induced current (GIC) flow information specified in Requirement R5 Part 5.1 is received.

Transmission Owners and Generator Owners are not required to comply with Requirement R10 prior to the compliance date for Requirement R10, regardless of when GIC flow information specified in Requirement R9 Part 9.1 is received.
**Action**
Approve the following project schedule for Project 2013-03 Geomagnetic Disturbance (GMD) Mitigation:

1. Finalization of the Standard Authorization Request (completed)
2. Initial Posting and Ballot of Standard(s) (June 2017)
3. Additional Postings and Ballots (as needed)
4. Final Ballot (March 2018)

**Background**
Section 4.4.1 of the Standard Processes Manual states:

**4.4.1: Project Schedule**
When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

On September 22, 2016, FERC issued [Order No. 830](#) directing NERC to develop certain modifications to Reliability Standard TPL-007-2. FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 29, 2018.

This document is submitted to provide the Standards Committee (SC) with an overview of the project schedule and to request SC approval. Updates will be presented to the SC via the project tracking spreadsheet at future calls and meetings.

This schedule is supported by the Project Management and Oversight Subcommittee liaison, Jennifer Sterling, Standards Developer Mark Olson, and the chair of the standard drafting team, Frank Koza.
**BAL-002-2 Standard Authorization Request and Standard Drafting Team**

**Action**
Authorize the posting of the BAL-002-2 Standard Authorization Request (SAR), developed in response to FERC Order No. 835 directives, for a 30-day informal comment period; and

a. Appoint the Project 2010-14.1 Standard Drafting Team (SDT)\(^1\) as the drafting team for the SAR, or

b. Solicit for SAR drafting members.

**Background**
On January 19, 2017, FERC issued Order No. 835\(^2\) approving Reliability Standard BAL-002-2. FERC’s order also directed NERC to make two modifications to the BAL-002-2 standard and revise two Violation Risk Factors (VRFs). The VRF revisions will be handled outside of this SAR, per the informational one-pager included in this Agenda package (Item 18b).

With regard to FERC’s directed modifications to BAL-002-2, the order stated:

> Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative.

NERC staff recommends that the attached SAR be posted for a 30-day informal comment period and that the Project 2010-14.1 SDT be appointed to review the comments from the SAR posting and develop the necessary modifications to Reliability Standard BAL-002-2 to address the FERC directives. The Project 2010-14.1 SDT has the necessary technical expertise, work process skills to address this project, and the availability to continue for the next phase of this project.

---

\(^1\) See page 2 for Project 2014-14.1 SDT roster.

<table>
<thead>
<tr>
<th>Name</th>
<th>Title</th>
<th>Company</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glenn Stephens</td>
<td>Manager – System Planning</td>
<td>Santee Cooper</td>
</tr>
<tr>
<td>Tom Siegrist</td>
<td>Consultant</td>
<td>Stone Mattheis Xenopoulos &amp; Brew, P.C.</td>
</tr>
<tr>
<td>Gerry Beckerle</td>
<td>Senior Transmission Operations Supervisor</td>
<td>Ameren</td>
</tr>
<tr>
<td>Howard Illian</td>
<td>President</td>
<td>Energy Mark</td>
</tr>
<tr>
<td>David Lemmons</td>
<td>Senior Consultant</td>
<td>Xcel Energy</td>
</tr>
<tr>
<td>Clyde Loutan</td>
<td>Senior Advisor</td>
<td>California ISO</td>
</tr>
<tr>
<td>LeRoy Patterson</td>
<td>Trainer</td>
<td>Grant County Public Utility District #2</td>
</tr>
<tr>
<td>Mark Prosperi-Porta</td>
<td>System Control Manger</td>
<td>BC Hydro</td>
</tr>
<tr>
<td>Tom Pruitt</td>
<td>Principal Engineer</td>
<td>Duke Energy</td>
</tr>
<tr>
<td>Jerry Rust</td>
<td>President</td>
<td>NWPP</td>
</tr>
</tbody>
</table>
NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

### Request to propose a new or a revision to a Reliability Standard

<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td>Date Submitted:</td>
<td></td>
</tr>
</tbody>
</table>

**SAR Requester Information**

<table>
<thead>
<tr>
<th>Name:</th>
<th>Darrel Richardson</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organization:</td>
<td>NERC staff</td>
</tr>
<tr>
<td>Telephone:</td>
<td>609.613.1848</td>
</tr>
<tr>
<td>Email:</td>
<td><a href="mailto:darrel.richardson@nerc.net">darrel.richardson@nerc.net</a></td>
</tr>
</tbody>
</table>

**SAR Type (Check as many as applicable)**

- [ ] New Standard
- [ ] Revision to Existing Standard
- [ ] Withdrawal of Existing Standard
- [ ] Urgent Action

**SAR Information**

**Industry Need (What is the industry problem this request is trying to solve?):**

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

“Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute
### Purpose or Goal (How does this request propose to address the problem described above?):

The primary goal of this SAR is to allow the standard drafting team (SDT) for this project to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

### Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):

The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission’s concerns.

### Brief Description (Provide a paragraph that describes the scope of this standard action.)

The SDT shall modify the standard, make any necessary revisions to Violation Risk Factors and Violation Severity Levels, develop an implementation plan, and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.

### Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The SDT’s execution of this SAR requires the SDT to address the FERC Order directives described above, or alternatively propose modifications that address the Commission’s concerns in the FERC Order. This SAR will specifically address either:

(A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or
SAR Information

(B) proposing an equally efficient and effective alternative.

<table>
<thead>
<tr>
<th>Reliability Functions</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>The Standard will Apply to the Following Functions (Check each one that applies.)</strong></td>
</tr>
<tr>
<td>□ Reliability Coordinator</td>
</tr>
<tr>
<td>✗ Balancing Authority</td>
</tr>
<tr>
<td>□ Interchange Authority</td>
</tr>
<tr>
<td>□ Planning Coordinator</td>
</tr>
<tr>
<td>□ Resource Planner</td>
</tr>
<tr>
<td>□ Transmission Planner</td>
</tr>
<tr>
<td>□ Transmission Service Provider</td>
</tr>
<tr>
<td>□ Transmission Owner</td>
</tr>
<tr>
<td>□ Transmission Operator</td>
</tr>
<tr>
<td>□ Distribution Provider</td>
</tr>
<tr>
<td>□ Generator Owner</td>
</tr>
<tr>
<td>□ Generator Operator</td>
</tr>
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</table>
### Reliability Functions

<table>
<thead>
<tr>
<th>Entity</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Purchasing-Selling Entity</td>
<td>Purchases or sells energy, capacity, and necessary reliability-related services as required.</td>
</tr>
<tr>
<td>Market Operator</td>
<td>Interface point for reliability functions with commercial functions.</td>
</tr>
<tr>
<td>Load-Serving Entity</td>
<td>Secures energy and transmission service (and reliability-related services) to serve the end-use customer.</td>
</tr>
</tbody>
</table>

### Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply).

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

Does the proposed Standard comply with all of the following Market Interface Principles?

<table>
<thead>
<tr>
<th>Principle</th>
<th>Enter (yes/no)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. A reliability standard shall not give any market participant an unfair competitive advantage.</td>
<td>Yes</td>
</tr>
<tr>
<td>2. A reliability standard shall neither mandate nor prohibit any specific market structure.</td>
<td>Yes</td>
</tr>
<tr>
<td>3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.</td>
<td>Yes</td>
</tr>
</tbody>
</table>
### Reliability and Market Interface Principles

4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

<table>
<thead>
<tr>
<th>Related Standards</th>
</tr>
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<tbody>
<tr>
<td><strong>Standard No.</strong></td>
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<table>
<thead>
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<tr>
<td><strong>SAR ID</strong></td>
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### Regional Variances

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<td>WECC</td>
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### Version History

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</tr>
</thead>
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<tr>
<td>1</td>
<td>June 3, 2013</td>
<td>Revised</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>August 29, 2014</td>
<td>Standards Information Staff</td>
<td>Updated template</td>
</tr>
</tbody>
</table>
**Frequency Response and Frequency Bias Setting - BAL-003-1.1**

**Action**
Authorize the posting of a BAL-003-1.1 Standard Authorization Request (SAR) for Project 2017-01 for a 30-day formal comment period. Authorize the posting for nominations of a SAR drafting team to consider stakeholder comments over a 14-day nomination period.

**Background**
NERC has received a SAR from the NERC Resources Subcommittee (RS) proposing modifications to BAL-003-1.1 and its supporting documentation. The RS developed this SAR to revise the Interconnection Frequency Response Obligation (IFRO) calculation in BAL-003-1 due to inconsistencies identified in the 2016 Frequency Response Annual Analysis Report (FRAA).¹

The issues identified within the SAR relate to:

1. Calculation of Interconnection Frequency Response Obligations (“IFROs”);
   a. The CBR ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligation to be carried, essentially penalizing improved performance;
   b. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point (point at which frequency decline is arrested) that exceeds the \( t_0 + 12 \) seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event, and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding \( t_0 + 12 \) seconds;

2. Review of the Resource Contingency Protection Criteria for each interconnection to ensure sufficient primary frequency response is maintained;

3. Clarification of language in Attachment A related to Frequency Response Reserve Sharing Groups, and the timeline for Frequency Response and Frequency Bias Setting activities;

4. Review of BAL-003 FRS Forms; and

5. Consideration of whether elements of Attachment A should be removed and captured in a NERC Operating Committee- approved Reference Document.

Several of these issues were anticipated and raised in more detail in the FRAA report that was accepted by the RS on August 25, 2016, and by the NERC Operating Committee on September 30, 2016, and filed with FERC on an informational basis in October 21, 2016.

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² \( t_0 \) is defined as the time of the event.
NERC staff recommends that the SAR be posted for a 30-day comment period. NERC staff further recommends posting a 14-day nomination period for a SAR drafting team to review comments and develop a final SAR.
NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

**Request to propose a new or a revision to a Reliability Standard**

<table>
<thead>
<tr>
<th>Title of Proposed Standard:</th>
<th>BAL-003-1 – Frequency Response and Frequency Bias Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Submitted:</td>
<td></td>
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**SAR Requester Information**

<table>
<thead>
<tr>
<th>Name:</th>
<th>Troy Blalock – Chair of the NERC Resource Subcommittee</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organization:</td>
<td>NERC Resource Subcommittee</td>
</tr>
<tr>
<td>Telephone:</td>
<td>803.217.2040</td>
</tr>
<tr>
<td>Email:</td>
<td><a href="mailto:Jblalock@scana.com">Jblalock@scana.com</a></td>
</tr>
</tbody>
</table>

**SAR Type (Check as many as applicable)**

- [ ] New Standard
- [X] Revision to Existing Standard
- [ ] Withdrawal of Existing Standard
- [ ] Urgent Action

**SAR Information**

**Industry Need (What is the industry problem this request is trying to solve?):**

The supporting documents for BAL-003-1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It is expected that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies outlined below, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval. The items that need to be addressed are:

When completed, please email this form to: sarcomm@nerc.com
SAR Information

1. The IFRO calculation in BAL-003-1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B.
3. Reevaluate the frequency nadir point limitations (currently limited to t₀ to t+12).
4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities.
5. The BAL-003-1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.

Purpose or Goal (How does this request propose to address the problem described above?):

Revise the BAL-003-1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency nadir point limitations (currently limited to t₀ to t+12), (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. (5) The BAL-003-1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps may be removed from Attachment A and captured in an ERO and NERC Operating Committee approved Reference Document such that timely process improvements can be made as future lessons are learned.

For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.

Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):

1. The IFRO calculation in BAL-003-1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B.
3. Reevaluate the frequency nadir point limitations (currently limited to t₀ to t+12).
4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities.
5. The BAL-003-1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.
<table>
<thead>
<tr>
<th>SAR Information</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Brief Description</strong> (Provide a paragraph that describes the scope of this standard action.)</td>
</tr>
<tr>
<td>During the 2016 annual evaluation of the values used in the calculation of the IFRO the above mentioned issues were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to ( t_0 ) to ( t+12 )), and (4) clarify language in Attachment A; (5) The BAL-003-1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.</td>
</tr>
<tr>
<td><strong>Detailed Description</strong> (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)</td>
</tr>
<tr>
<td>Consider revising the BAL-003-1 standard concerning #1 above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. This ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved performance. Consider revising the BAL-003-1 standard concerning #2 above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the “largest resource event in last 10 years”, which is the August 4, 2007 event. The standard drafting team should revisit this issue for modifications to BAL-003-1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection. Consider revising the BAL-003-1 standard concerning #3 above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the ( t_0 +12 ) seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond ( t_0+12 ) seconds. The actual event nadir can occur at any time, including beyond...</td>
</tr>
</tbody>
</table>
SAR Information

the time period used for calculating Value B (t₀+20 through t₀+52 seconds), and may be the value known as Point C’ which typically occurs in the 72 to 95 second range after t₀.

Consider revising BAL-003-1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline.

Consider revising the BAL-003-1 standard concerning #4 above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<table>
<thead>
<tr>
<th>Function</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability Coordinator</td>
<td>Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.</td>
</tr>
<tr>
<td>Balancing Authority</td>
<td>Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.</td>
</tr>
<tr>
<td>Interchange Authority</td>
<td>Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.</td>
</tr>
<tr>
<td>Planning Coordinator</td>
<td>Assesses the longer-term reliability of its Planning Coordinator Area.</td>
</tr>
<tr>
<td>Resource Planner</td>
<td>Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.</td>
</tr>
<tr>
<td>Transmission Planner</td>
<td>Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.</td>
</tr>
</tbody>
</table>
### Reliability Functions

<table>
<thead>
<tr>
<th>Role</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Service Provider</td>
<td>Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).</td>
</tr>
<tr>
<td>Transmission Owner</td>
<td>Owns and maintains transmission facilities.</td>
</tr>
<tr>
<td>Transmission Operator</td>
<td>Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.</td>
</tr>
<tr>
<td>Distribution Provider</td>
<td>Delivers electrical energy to the end-use customer.</td>
</tr>
<tr>
<td>Generator Owner</td>
<td>Owns and maintains generation facilities.</td>
</tr>
<tr>
<td>Generator Operator</td>
<td>Operates generation unit(s) to provide real and reactive power.</td>
</tr>
<tr>
<td>Purchasing-Selling Entity</td>
<td>Purchases or sells energy, capacity, and necessary reliability-related services as required.</td>
</tr>
<tr>
<td>Market Operator</td>
<td>Interface point for reliability functions with commercial functions.</td>
</tr>
<tr>
<td>Load-Serving Entity</td>
<td>Secures energy and transmission service (and reliability-related services) to serve the end-use customer.</td>
</tr>
</tbody>
</table>

### Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply).

- **1.** Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
- **2.** The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
- **3.** Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
- **4.** Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
- **5.** Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
- **6.** Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
### Reliability and Market Interface Principles

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
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</thead>
<tbody>
<tr>
<td>7.</td>
<td>The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.</td>
</tr>
<tr>
<td>8.</td>
<td>Bulk power systems shall be protected from malicious physical or cyber attacks.</td>
</tr>
</tbody>
</table>

Does the proposed Standard comply with all of the following Market Interface Principles?

<table>
<thead>
<tr>
<th></th>
<th>Enter (yes/no)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>A reliability standard shall not give any market participant an unfair competitive advantage.</td>
</tr>
<tr>
<td>2.</td>
<td>A reliability standard shall neither mandate nor prohibit any specific market structure.</td>
</tr>
<tr>
<td>3.</td>
<td>A reliability standard shall not preclude market solutions to achieving compliance with that standard.</td>
</tr>
<tr>
<td>4.</td>
<td>A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.</td>
</tr>
</tbody>
</table>

### Related Standards

<table>
<thead>
<tr>
<th>Standard No.</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
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</tr>
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### Related SARs

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<thead>
<tr>
<th>SAR ID</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td></td>
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</tbody>
</table>
### Related SARs

<table>
<thead>
<tr>
<th>Region</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERCOT</td>
</tr>
<tr>
<td>FRCC</td>
</tr>
<tr>
<td>MRO</td>
</tr>
<tr>
<td>NPCC</td>
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<tr>
<td>RFC</td>
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<tr>
<td>SERC</td>
</tr>
<tr>
<td>SPP</td>
</tr>
<tr>
<td>WECC</td>
</tr>
</tbody>
</table>

### Regional Variances

<table>
<thead>
<tr>
<th>Region</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>ERCOT</td>
<td>None.</td>
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<tr>
<td>SPP</td>
<td>None.</td>
</tr>
<tr>
<td>WECC</td>
<td>None.</td>
</tr>
</tbody>
</table>

### Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Owner</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>June 3, 2013</td>
<td></td>
<td>Revised</td>
</tr>
<tr>
<td>1</td>
<td>August 29, 2014</td>
<td>Standards Information Staff</td>
<td>Updated template</td>
</tr>
</tbody>
</table>
Project 2016-EPR-01 for PER-003-1 and PER-004-2

Action
Accept the Periodic Review Team’s recommendation to revise PER-003-1, retire PER-004-2, and authorize the posting of PER-003-1 and PER-004-2 Standard Authorization Requests (SAR) for an initial 30-day informal comment period. Appoint the Project 2016-EPR-01 Enhanced Periodic Review Team (PRT) as the SAR drafting team and the standard drafting team.

Background
In September 2016 the Project 2016-EPR-01 PER Enhanced PRT began their review of the Personnel Performance, Training, and Qualifications (PER) standards. The project reviewed Reliability Standards PER-001-0.2, PER-003-1, and PER-004-2. As part of its review, the PRT referenced the following background documents: 1. the currently-enforceable PER-001-0.2, PER-003-1, and PER-004-2 standards; 2. outstanding issues and directives pertaining to the aforementioned standards; 3. the Independent Experts Report; and 4. Paragraph 81 criteria.

On January 10, 2017, the PRT posted their recommendations addressing the aforementioned standards. The PRT will not review standard PER-001-0.2, as it was approved to be retired through a different project. The recommendations are detailed in the attached Periodic Review Template. The industry significantly supported the PRT’s recommendations.

NERC staff recommends that the attached SAR be posted for a 45-day comment period and that the Project 2016-EPR-01 PRT be appointed to review the comments from the SAR posting and develop the necessary modifications to Reliability Standards PER-003-1 and PER-004-2.

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1 The comments received from the posting of the recommendations can be found at the following link: http://www.nerc.com/pa/Stand/Project%20201601%20Enhanced%20Periodic%20Review%20of%20PER%20Standards_Comments_Received_02242017.pdf
Periodic Review Template: PER-003-1
Operating Personnel Credentials
December 2016

Introduction
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.1 The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.2 Consistent with Section 13 of the Standard Processes Manual, the SC may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal, and compliance experts. The technical experts maintain authority over the technical details of the periodic review. Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team’s considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

<table>
<thead>
<tr>
<th>Standing Review Team</th>
<th>Plus Section 13 (SMEs):</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-CIP Standards</td>
<td>The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the</td>
</tr>
<tr>
<td>Chairs of the following NERC Standing Committees³:</td>
<td></td>
</tr>
<tr>
<td>• Standards Committee (Also, the SC chair or his/her delegate from the</td>
<td></td>
</tr>
</tbody>
</table>

---

²Other reliability standards included as part of the Review Team’s periodic review were PER-004-2 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).
³Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.

The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

---

4 The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team’s review of a standard(s), and another SC member to chair a review of another standard(s).

5 Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

**Applicable Reliability Standard:** PER-003-1

**Team Members (include name and organization):**

1. Patti Metro, Nation Rural Electric Cooperative Association
2. Lauri Jones, Pacific Gas and Electric Company
3. Heather Morgan, EDP Renewables North America LLC
4. Jeffrey Sunvick, Western Area Power Administration
5. Jimmy Womack, Southwest Power Pool
6. Brad Perrett, Minnesota Power
7. Carolyn White Wilson, Duke Energy Corporation
8. Michael B. Hoke, PJM Interconnection LLC
9. Danny W. Johnson, Xcel Energy
10. Darrel Richardson, NERC Senior Standards Developer
11. Candice Castaneda, NERC Counsel
12. Michael Brytowski, Great River Energy PMOS Representative

**Background Information (to be completed initially by NERC staff)**

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? *(If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*
   - Yes
   - ❌ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? *(If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard.)*
   - Yes
   - ❌ No

   Please explain:
3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes
☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes
☐ No

Please explain:

Questions for the Review Team
If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. Reliability Need, Paragraph 81: Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use Attachment 2: Paragraph 81 Criteria to make this determination.

☐ Yes
☒ No

Please summarize your application of Paragraph 81 Criteria, if any:

2. Clarity: From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
d. Should the requirements stand alone as is, or should they be consolidated with other standards?

e. Is the Reliability Standard complete and self-contained?

f. Does the Reliability Standard use consistent terminology?

☐ Yes
☐ No

Please summarize your assessment: Although the response to the parent question above is “No,” examination of its subparts (a) – (g) has led the Review Team to recommend a clarifying revision.
The Project 2016-EPR-01 PER Review Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the NERC System Operator Certification Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

3. Definitions: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes
☒ No

Please explain:

4. Compliance Elements: Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), ViolationSeverity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative, FERC, and NERC guidelines?

☒ Yes
☐ No

If you answered “No,” please identify which elements require revision, and why:

5. Consistency with Other Reliability Standards: Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

☐ Yes
☒ No
If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors**: Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors?
   - [ ] Yes
   - [x] No

   If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?
      - [x] Yes
      - [ ] No
   b. Is there a concern that it is not cost effective as drafted?
      - [ ] Yes
      - [x] No

   **Please summarize your assessment of the practicability of the standard**:

8. **Consideration of Generator and Transmission Interconnection Facilities**: Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **N/A to this standard**.
   - [ ] Yes
   - [ ] No

   **Guiding Questions**:
   a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)
b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results-Based Standard:** Is the Reliability Standard drafted as a results-based standard?

   - Yes
   - No

   **If not, please summarize your assessment:**

   *Guiding Questions:*

   a. Does the Reliability Standard address performance, risk (prevention), and capability?
      
   - Yes
   - No

   b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?
      
   - Yes
   - No

   c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard?[^6]
      
   - Yes
   - No

---

11. Content

10. **Technical accuracy**: Is the content of the Requirements technically correct, including identifying who does what and when?

   ☒ Yes
   ☐ No

   **If not, please summarize your assessment:**

11. **Functional Model**: Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

   ☒ Yes
   ☐ No

   **If not, please summarize your assessment:**

12. **Applicability**: Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

   ☐ Yes
   ☒ No

   **If so, please summarize your assessment:**

13. **Reliability Gaps**: Are the appropriate actions for which there should be accountability included, or is there a gap?

   ☐ Yes
   ☒ No

   **If a gap is identified, please explain:**

14. **Technical Quality**: Does the Reliability Standard have a technical basis in engineering and operations?

   ☒ Yes
   ☐ No
If not, please summarize your assessment:

15. Does the Reliability Standard reflect a higher solution than the lowest common denominator?

☐ Yes
☐ No

If not, please summarize your assessment:

16. Related Regional Reliability Standards: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes
☐ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING
Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team’s conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.

Recommendation
The answers to the questions above, along with its Red, Yellow, or Green grading, and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):
☐ REAFFIRM (This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN

☒ REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW

☐ REVISE (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED

☐ RETIRE (Would include revision of associated RSAW.) RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR):

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

**Preliminary Recommendation posted for industry comment (date):** January 10, 2017
Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

- REAFFIRM (This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.)  GREEN

- REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)  (Would include revision of associated RSAW.)  YELLOW

- REVISE (The recommended revisions are required to support reliability.)  (Would include revision of associated RSAW.)  RED

- RETIRE (Would include revision of associated RSAW.)  RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR):

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Date submitted to Standards Committee: June 14, 2017
Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, “Acceptance Criteria of a Reliability Standard.”

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?
Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC’s reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.
Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts. Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

**Criterion A (Overarching Criterion)**
The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines “reliable operation” as: “...operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

**Criteria B (Identifying Criteria)**

**B1. Administrative**
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability, and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability, and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3, and B4. Strictly administrative functions do not inherently negatively impact reliability directly, and where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

---

7 In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.
B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit, and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (e.g., plan, policy, or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability, or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with, or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC, or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure, or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.
This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (e.g., Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by the Registered Ballot Body, and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that
it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

**C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?**
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

**C5. Is there a possible negative impact on NERC’s published and posted reliability principles?**
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

**Reliability Principles**
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

- **Principle 1.** Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

- **Principle 2.** The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

- **Principle 3.** Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

- **Principle 4.** Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (footnote omitted)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.
Attachment 3: Independent Expert Evaluation Process

**Figure 1: Evaluation Flow Chart**

- **Does the Requirement support Reliability?**
  - **Yes:**
    - **Guideline Bucket:** Re-draft as a Guideline
    - **Does it meet Para 81 Criteria OR Is a Guideline more appropriate?**
      - **Yes:**
        - **Content Revision Needed**
      - **No:**
        - **Steady State**
  - **No:**
    - **Delete Requirement**
Introduction
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard. 1 The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. 2 Consistent with Section 13 of the Standard Processes Manual, the SC may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal, and compliance experts. The technical experts maintain authority over the technical details of the periodic review. Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team’s considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

<table>
<thead>
<tr>
<th>Non-CIP Standards</th>
<th>Standing Review Team</th>
<th>Plus Section 13 (SMEs):</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chairs of the following NERC Standing Committees 3:</td>
<td>The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the</td>
<td></td>
</tr>
<tr>
<td>• Standards Committee (Also, the SC chair or his/her delegate from the</td>
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<td></td>
</tr>
</tbody>
</table>

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2Other reliability standards included as part of the Review Team’s periodic review were PER-003-1 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

3Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
SC will chair the Standing Review Team\(^4\)
- Planning Committee
- Operating Committee
The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.

| CIP Standards | Chairs of the following NERC Standing Committees\(^5\):
|---------------|--------------------------------------------------|
|               | • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team)
|               | • CIPC                                            |

Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

\(^4\) The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team’s review of a standard(s), and another SC member to chair a review of another standard(s).

\(^5\) Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

<table>
<thead>
<tr>
<th>Applicable Reliability Standard: PER-004-2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team Members (include name and organization):</td>
</tr>
<tr>
<td>1. Patti Metro, Nation Rural Electric Cooperative Association</td>
</tr>
<tr>
<td>2. Lauri Jones, Pacific Gas and Electric Company</td>
</tr>
<tr>
<td>3. Heather Morgan, EDP Renewables North America LLC</td>
</tr>
<tr>
<td>4. Jeffrey Sunvick, Western Area Power Administration</td>
</tr>
<tr>
<td>5. Jimmy Womack, Southwest Power Pool</td>
</tr>
<tr>
<td>6. Brad Perrett, Minnesota Power</td>
</tr>
<tr>
<td>7. Carolyn White Wilson, Duke Energy Corporation</td>
</tr>
<tr>
<td>8. Michael B. Hoke, PJM Interconnection LLC</td>
</tr>
<tr>
<td>9. Danny W. Johnson, Xcel Energy</td>
</tr>
<tr>
<td>10. Darrel Richardson, NERC Senior Standards Developer</td>
</tr>
<tr>
<td>11. Candice Castaneda, NERC Counsel</td>
</tr>
<tr>
<td>12. Michael Brytowski, Great River Energy PMOS Representative</td>
</tr>
</tbody>
</table>

**Background Information (to be completed initially by NERC staff)**

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? *(If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*
   - [ ] Yes
   - [X] No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? *(If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard.)*
   - [ ] Yes
   - [X] No

Please explain:
3. Is the Reliability Standard one of the most violated Reliability Standards?

☑ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes
☐ No

**Please explain:**

**Questions for the Review Team**

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

**1. Quality**

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

☑ Yes
☐ No

**Please summarize your application of Paragraph 81 Criteria, if any:**

This standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements and PER-004-2 may be retired with little to no effect on reliability. Specifically, PER-004-2’s requirements are duplicated in standards:

- PER-003-1, R1
- PER-005-2, R2 and R3
- IRO-002-4, R3 and R4
• EOP-004-2, R2
• IRO-008-2, R1, R2, and R4
• IRO-009-2, R1 – R4
• IRO-010-2, R1 – R3
• IRO-014-3, generally
• IRO-018-1, R1-R3

Please refer to Page 10 of this document for a detailed justification for retirement of these requirements.

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☐ Yes
☒ No

Please summarize your assessment:

3. **Definitions:** Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes
☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative, FERC, and NERC guidelines?
Yes
No

If you answered “No,” please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

   □ Yes
   □ No

   If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors?

   □ Yes
   □ No

   If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable:**
   
   a. Can the Reliability Standard be practically implemented?

      □ Yes
      □ No

   b. Is there a concern that it is not cost effective as drafted?

      □ Yes
      □ No

   Please summarize your assessment of the practicability of the standard:
8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **Not Applicable.**

   - Yes
   - No

**Guiding Questions:**

a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results-Based Standard:** Is the Reliability Standard drafted as a results-based standard?

   - Yes
   - No

**If not, please summarize your assessment:**

**Guiding Questions:**

a. Does the Reliability Standard address performance, risk (prevention), and capability?

   - Yes
   - No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?
c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard\(^6\)?

- Yes
- No

II. Content

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

- Yes
- No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

- Yes
- No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

- Yes
- No

If so, please summarize your assessment:

13. **Reliability Gaps**: Are the appropriate actions for which there should be accountability included, or is there a gap?

- [ ] Yes
- [x] No

*If a gap is identified, please explain:*

14. **Technical Quality**: Does the Reliability Standard have a technical basis in engineering and operations?

- [x] Yes
- [ ] No

*If not, please summarize your assessment:*

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

- [x] Yes
- [ ] No

*If not, please summarize your assessment:*

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

- [ ] Yes
- [x] No

*If yes, please identify the regional standard(s) and summarize your assessment:*

**RED, YELLOW GREEN GRADING**

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team’s conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team,
minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.

**Recommendation**

The answers to the questions above, along with its Red, Yellow, or Green grading, and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

**Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):**

- ![ ] **REAFFIRM** (This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN
- ![ ] **REVISE** (The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW
- ![ ] **REVISE** (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED
- ![ ] **RETIRE** (Would include revision of associated RSAW.) RED

**Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR):**

PER-004-2 R1 is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop, and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, “Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator’s operating personnel...” In addition, IRO-002-4 R3 states that, “Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to
determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area.” EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, “Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address ...(SOL) and (IROL) exceedances...” and R4 states, “Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.” Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator’s maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, “Present time as opposed to future times,” while Real-time Assessment is defined as “An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.” Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards. PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3, and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or
actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments, and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator’s operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Preliminary Recommendation posted for industry comment (date): January 10, 2017
Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.)*  GREEN

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)*  (Would include revision of associated RSAW.)  YELLOW

☐ REVISE *(The recommended revisions are required to support reliability.)*  (Would include revision of associated RSAW.)  RED

☒ RETIRE *(Would include revision of associated RSAW.)*  RED

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR):*

See justification above.

**Date submitted to Standards Committee:** June 14, 2017
Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, “Acceptance Criteria of a Reliability Standard.”

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?
Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC’s reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.
Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts. Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

**Criterion A (Overarching Criterion)**
The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines “reliable operation” as: “… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

**Criteria B (Identifying Criteria)**

**B1. Administrative**
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability, and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability, and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3, and B4. Strictly administrative functions do not inherently negatively impact reliability directly, and where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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7 In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.
B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit, and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (e.g., plan, policy, or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability, or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with, or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC, or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure, or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.
This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

**B7. Redundant**
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (e.g., Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

**Criteria C (Additional data and reference points)**
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

**C1. Was the Reliability Standard requirement part of a FFT filing?**
The application of this criterion involves determining whether the requirement was included in a FFT filing.

**C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?**
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by the Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

**C3. What is the VRF of the Reliability Standard requirement?**
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that
it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC’s published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In other words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.
Attachment 3: Independent Expert Evaluation Process

Evaluation Flow Chart

- Does the Requirement support Reliability?
  - Yes
    - Guideline Bucket - Re-draft as a Guideline
  - No
    - Delete Requirement

- Does it meet Para 81 Criteria OR Is a Guideline more appropriate?
  - Yes
    - Guideline Bucket - Re-draft as a Guideline
  - No
    - Content Revision Needed

- Is there a GAP? Or Are the applicable Functional Entities Incorrect? Or Is it technically incorrect? (Including correct level of actions for accountability - Who, What, When)
  - Yes
    - Content Revision Needed
  - No
    - Steady State

- Does it meet the quality criteria? Or Should it be kept as it is and not collapsed with other standards/requirements?
  - Yes
    - Steady State
  - No
    - Quality Revision Needed

Figure 1: Evaluation Flow Chart
NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

**Request to propose a new or a revision to a Reliability Standard**

<table>
<thead>
<tr>
<th>Title of Proposed Standard:</th>
<th>PER-003-1 Operating Personnel Credentials and PER-004-2 Reliability Coordination — Staffing</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date Submitted:</td>
<td>TBD</td>
</tr>
</tbody>
</table>

**SAR Requester Information**

<table>
<thead>
<tr>
<th>Name:</th>
<th>Patti Metro</th>
</tr>
</thead>
<tbody>
<tr>
<td>Organization:</td>
<td>Chair - Project 2016-EPR-01 PER</td>
</tr>
<tr>
<td>Telephone:</td>
<td>(703) 907-5817</td>
</tr>
<tr>
<td>Email:</td>
<td><a href="mailto:patti.metro@nreca.coop">patti.metro@nreca.coop</a></td>
</tr>
</tbody>
</table>

**SAR Type (Check as many as applicable)**

- [ ] New Standard
- [x] Revision to Existing Standard
- [ ] Withdrawal of Existing Standard
- [ ] Urgent Action

**SAR Information**

**Industry Need (What is the industry problem this request is trying to solve?):**

Clarify that under PER-003-1, the process for obtaining NERC certifications is described in the NERC System Operator Certification Program.

The requirements of PER-004-2 are duplicative with requirements in several other standards that explain in detail the staffing requirements of personnel conducting the Reliability Coordinator function.
<table>
<thead>
<tr>
<th><strong>SAR Information</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Purpose or Goal (How does this request propose to address the problem described above?):</strong></td>
</tr>
<tr>
<td>The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.</td>
</tr>
<tr>
<td>The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.</td>
</tr>
<tr>
<td><strong>Identify the Objectives of the proposed standard’s requirements (What specific reliability deliverables are required to achieve the goal?):</strong></td>
</tr>
<tr>
<td>N/A</td>
</tr>
<tr>
<td><strong>Brief Description (Provide a paragraph that describes the scope of this standard action.)</strong></td>
</tr>
<tr>
<td>The Project 2016-EPR-01 PER team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2, and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.</td>
</tr>
<tr>
<td>The PER-004-2 standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements. Specifically, PER-004-2’s requirements are duplicated in standards:</td>
</tr>
<tr>
<td>• PER-003-1, R1</td>
</tr>
<tr>
<td>• PER-005-2, R2 and R3</td>
</tr>
<tr>
<td>• IRO-002-4, R3 and R4</td>
</tr>
<tr>
<td>• EOP-004-2, R2</td>
</tr>
<tr>
<td>• IRO-008-2, R1, R2, and R4</td>
</tr>
<tr>
<td>• IRO-009-2, R1 – R4</td>
</tr>
<tr>
<td>• IRO-010-2, R1 – R3</td>
</tr>
<tr>
<td>• IRO-014-3, generally</td>
</tr>
<tr>
<td>• IRO-018-1, R1-R3</td>
</tr>
</tbody>
</table>
SAR Information

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2, and R3 to ensure that stakeholders (now and in the future) understand the connection between the Standard and the Program Manual. The PRT suggests for consideration the following language be used for the footnote “The certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.”

Concerning PER-004-2, the standard is duplicative and all requirements are covered in other reliability standards. PER-004-2 Requirement R1 mandates Reliability Coordinators to be staffed with NERC-certified operators 24 hours per day, seven days per week. PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop, and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Furthermore, IRO-002-4 R4 (enforceable 4/1/2017) requires that, “Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator’s operating personnel…” In addition, IRO-002-4 R3 states that, “Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area.” EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, “Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address ...(SOL) and (IROL) exceedances...” and R4 states, “Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes.” Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator’s maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, “Present time as opposed to future times,” while Real-time Assessment is defined as “An examination of existing and expected system conditions, conducted by
collecting and reviewing immediately available data.” Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards.

PER-004-2 Requirement R2 provides that the Reliability Coordinator operating personnel shall place attention on SOLs and IROLs and inter-tie facility limits. Protocols must be in place to allow the Reliability Coordinator operating personnel to have the best available information at all times. This is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3, and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.
SAR Information

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments, and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator’s operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

<table>
<thead>
<tr>
<th>Function</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reliability Coordinator</td>
<td>Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.</td>
</tr>
<tr>
<td>Balancing Authority</td>
<td>Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.</td>
</tr>
<tr>
<td>Interchange Authority</td>
<td>Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.</td>
</tr>
<tr>
<td>Planning Coordinator</td>
<td>Assesses the longer-term reliability of its Planning Coordinator Area.</td>
</tr>
</tbody>
</table>
Reliability Functions

<table>
<thead>
<tr>
<th>Resource Planner</th>
<th>Develops a one-year plan for the resource adequacy of its specific loads within a Planning Coordinator area.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Planner</td>
<td>Develops a one-year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.</td>
</tr>
<tr>
<td>Transmission Service Provider</td>
<td>Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).</td>
</tr>
<tr>
<td>Transmission Owner</td>
<td>Owns and maintains transmission facilities.</td>
</tr>
<tr>
<td>Transmission Operator</td>
<td>Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.</td>
</tr>
<tr>
<td>Distribution Provider</td>
<td>Delivers electrical energy to the end-use customer.</td>
</tr>
<tr>
<td>Generator Owner</td>
<td>Owns and maintains generation facilities.</td>
</tr>
<tr>
<td>Generator Operator</td>
<td>Operates generation unit(s) to provide real and reactive power.</td>
</tr>
<tr>
<td>Purchasing-Selling Entity</td>
<td>Purchases or sells energy, capacity, and necessary reliability-related services as required.</td>
</tr>
<tr>
<td>Market Operator</td>
<td>Interface point for reliability functions with commercial functions.</td>
</tr>
<tr>
<td>Load-Serving Entity</td>
<td>Secures energy and transmission service (and reliability-related services) to serve the end-use customer.</td>
</tr>
</tbody>
</table>

Reliability and Market Interface Principles

Applicable Reliability Principles (Check all that apply).

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The security of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?

<table>
<thead>
<tr>
<th></th>
<th>Enter (yes/no)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. A reliability standard shall not give any market participant an unfair competitive advantage.</td>
<td>YES</td>
</tr>
<tr>
<td>2. A reliability standard shall neither mandate nor prohibit any specific market structure.</td>
<td>YES</td>
</tr>
<tr>
<td>3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.</td>
<td>YES</td>
</tr>
<tr>
<td>4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.</td>
<td>YES</td>
</tr>
</tbody>
</table>
### Related SARs

<table>
<thead>
<tr>
<th>SAR ID</th>
<th>Explanation</th>
</tr>
</thead>
<tbody>
<tr>
<td>N/A</td>
<td></td>
</tr>
</tbody>
</table>

### Regional Variances

<table>
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<th>Region</th>
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<td>FRCC</td>
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<td>MRO</td>
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<td>NPCC</td>
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<td>SPP</td>
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<td>WECC</td>
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Version History

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<td>June 3, 2013</td>
<td></td>
<td>Revised</td>
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<td>1</td>
<td>August 29, 2014</td>
<td>Standards Information Staff</td>
<td>Updated template</td>
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Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards

Action
Accept the recommendation of the periodic review team (PRT) to reaffirm Reliability Standards VAR-001-4.1 (Voltage and Reactive Control) and VAR-002-4 (Generator Operation for Maintaining Network Voltage Schedules) and submit the reaffirmation to the Board of Trustees for adoption.

Background
Section 13 of the NERC Standard Processes Manual provides that each Reliability Standard shall be reviewed at least once every 10 years by a team of subject matter experts appointed by the Standards Committee, who will recommend whether the reviewed standard should be reaffirmed, revised, or withdrawn. Section 13 provides, in pertinent part:

Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

The PRT conducted a review of Reliability Standards VAR-001 and VAR-002. The Standard Committee’s Enhanced Periodic Review Standing Team provided standards grades to guide the periodic reviews. This included background information, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standards will be: reaffirmed as is (i.e., no changes needed); revised (which may include revising or retiring one or more requirements); or withdrawn.
As part of its review, the PRT considered background documents, including the currently-enforceable VAR-001, and VAR-002 standards; outstanding issues and directives pertaining to these standards; the Independent Experts Report; and Paragraph 81 criteria.

The PRT posted an Enhanced Periodic Review template for VAR-001-4.1 and VAR-002-4 from February 28, 2017 to April 13, 2017 for industry comment. The PRT completed its comprehensive review of VAR-001-4.1 and VAR-002-4 on May 19, 2017, including considering feedback received from industry.

The team found the standards are sufficient to protect reliability and meet their stated reliability objectives, and therefore, the team recommends reaffirming the standards; however, the team identified that there may be future opportunity to improve non-substantive or insignificant quality and content issues.

Industry comments also affirmed that the standards: 1. are sufficient to protect reliability, 2. meet the reliability objective of the standards; and 3. no immediate revisions are necessary. See Consideration of Comments:

Consideration of Comments of VAR-001-4.1
Consideration of Comments of VAR-002-4
Periodic Review Recommendations:
VAR-001-4.1 - Voltage and Reactive Control
May 19, 2017

Executive Summary
The periodic review team completed a comprehensive review of VAR-001-4.1 – Voltage and Reactive Control. The team found the standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue. Industry comments also affirmed that the standard: 1) is sufficient to protect reliability, 2) it meets the reliability objective of the standard, and 3) no immediate revision is necessary. The following are the observations and recommendations of the periodic review team.

Introduction
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute (ANSI) as an American National Standard.¹ The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team, which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standard Processes Manual (SPM),² the SC may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.

Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the standard(s) by the Review Team, and document the Review Team’s considerations and recommendations. The Review Team posted the completed template containing its recommendations for information and stakeholder input, as required by Section 13 of the NERC SPM.

¹American National Standards Institute website: https://www.ansi.org/
### Review Team Composition

<table>
<thead>
<tr>
<th></th>
<th>Standing Review Team</th>
<th>Plus Section 13 (SMEs):</th>
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<tbody>
<tr>
<td><strong>Non-CIP Standards</strong></td>
<td>Chairs of the following NERC Standing Committees(^3):</td>
<td>The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.</td>
</tr>
<tr>
<td></td>
<td>• SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)(^4)</td>
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<tr>
<td></td>
<td>• Planning Committee</td>
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<td></td>
<td>• Operating Committee (A regional representative will be included on the Standing Review Team.)</td>
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<tr>
<td></td>
<td>The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.</td>
<td></td>
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<tr>
<td><strong>CIP Standards</strong></td>
<td>Chairs of the following NERC Standing Committees(^5):</td>
<td>The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.</td>
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<td></td>
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<tr>
<td></td>
<td>• CIPC</td>
<td></td>
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</table>

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the standard as steady-state (Green); or

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\(^3\) Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

\(^4\) The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team’s review of a standard(s), and another SC member to chair a review of another standard(s).

\(^5\) Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard; however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of, the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Scott Barfield-McGinnis via email or by telephone at 404-446-9689.

Applicable Reliability Standard: VAR-001-4.1 & VAR-002-4

Team Members (include name and organization):

1. Stephen Solis (Chair), Electric Reliability Council of Texas, Inc.
2. Dennis Sauriol (Vice Chair), American Electric Power
3. Alex Chua, Pacific Gas and Electric
4. Kevin Harrison, ITC Holdings
5. Bill Harm, PJM Interconnection, LLC
6. Tim Kucey, PSEG Fossil, LLC

Date Review Completed: May 19, 2017

Background Information (to be completed initially by NERC staff)

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)
   
   ☐ Yes
   ☑ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard.)

   ☐ Yes
   ☑ No

Please explain:
3. Is the Reliability Standard one of the most violated Reliability Standards?
   - [ ] Yes
   - [x] No

   Please explain:

   If so, does the cause of the frequent violation appear to be a lack of clarity in the language?
   - [ ] Yes
   - [ ] No

   Please explain:

**Questions for the Review Team**

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff, as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

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### I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*
   - [ ] Yes
   - [x] No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obvious ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
c. Are the requirements inconsistent with the purpose of the Reliability Standard?

d. Are the requirements not stand alone as is, or should they be consolidated with other standards?

e. Is the Reliability Standard incomplete and not self-contained?

f. Does the Reliability Standard use inconsistent terminology?
   - [ ] Yes
   - [x] No

Please summarize your assessment:

3. Definitions: Do any of the defined terms used within the Reliability Standard need to be refined?
   - [ ] Yes
   - [x] No

Please explain:

4. Compliance Elements: Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative (RAI) and FERC and NERC guidelines?
   - [x] Yes
   - [ ] No

If you answered “No,” please identify which elements require revision, and why:

5. Consistency with Other Reliability Standards: Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?
   - [ ] Yes
   - [x] No

If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:
6. **Changes in Technology, System Conditions, or other Factors**: Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

☐ Yes
☐ No

If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

The periodic review team affirms that there may be future opportunity to revise the standard or provide technical guidance (e.g., guideline) outside of a Reliability Standard. Industry submitted comments identifying that the newly approved IRO/TOP reliability standards should address these issues, although additional defense-in-depth could be considered as noted below.

Requirement R2 requires the Transmission Operator to maintain sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. The standard’s purpose statement notes that reactive resources among other things are monitored. There does not appear to be a requirement to monitor reactive resources (i.e., reserves) to ensure sufficiency. A few comments supported explicit monitoring of reactive reserves; however, the majority of industry comments indicated that the TOP/IRO standards address the issue of monitoring.

Requirement R4 does not require a review of the exemption either periodically or triggered by changes such as changes in technology, system conditions or other factors. These conditions may require a review of the exemption criteria; and the generators that may have been exempted by the Transmission Operator. Industry submitted comments that any exempt units that would cause a reliability issue would be discovered as the Transmission Operator performs the Operational Planning Analysis (OPA) and Real-time Assessment (RTA); therefore, there is no need to require a periodic review of exemption criteria. A few comments supported a periodic review of an exempted generating unit.

For Requirement R5, the Generator Operator may need to raise concerns to the Transmission Operator over the inability to meet the voltage schedule. This concern may result in an exemption, voltage schedule revision, or possibly some other action. This concern could be addressed with a revision to the Standard or some equivalent technical guidance (e.g., guideline). The requirement does not have a feedback loop to raise such concerns. Industry submitted comments that the lack of reserves on a single unit would not pose a reliability issue regarding the need for a periodic review. Any issues involving multiple generating units would be identified as part of an OPA or RTA.

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?
      ☒ Yes
      ☐ No
   b. Is there a concern that it is not cost effective as drafted?
      ☐ Yes
Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities**: Is responsibility for generator Interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard?

☐ Yes
☐ No

*Guiding Questions:*

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   *Response: The standard is not applicable to GOPs continent-wide and only GOPs according to the Western Interconnection variance in the standard. There is no ambiguity about the inclusion of generator Interconnection Facilities.*

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

   *Response: The standard is applicable to Transmission Operators. There is no reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard.*

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   *Response: The standard is applicable to Transmission Operators. There is no ambiguity about the inclusion of Transmission Interconnection Facilities.*

9. **Results-Based Standard (RBS)**: Is the Reliability Standard drafted as a RBS?

☐ Yes
☐ No
If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?
   - Yes
   - No

b. Does the Reliability Standard follow the RBS format (for example, requirement and part structure) in Attachment 1?
   - Yes
   - No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard⁶?
   - Yes
   - No

II. Content

10. Technical accuracy: Is the content of the requirements technically correct, including identifying who does what and when?
   - Yes
   - No

If not, please summarize your assessment:

As VAR-001-4.1 Requirement R5 is written, the Transmission Operator (TOP) has flexibility to determine the duration that a generator can be outside the voltage bandwidth. A TOP may have varying criteria depending on the specific unit size, location, amount that the unit is outside of the target or bandwidth. If the TOP does not specify a timing portion (i.e., duration when notification required) to its notification requirements in Part 5.2 (e.g., outside range for 5 minutes), there can be a lack of clarity of the notification requirements for the Generator Operator. The periodic review team recommends that there may be future opportunity to provide technical guidance (e.g., guideline) outside of a Reliability Standard. Industry comments identified that VAR-001 Requirement

⁶ Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of:
5.2 already provides the flexibility for the TOP to specify a time duration and that requiring a time duration would be prescriptive.

VAR-001-4.1, Requirement R5 does not include the Reliability Coordinator (RC) as a recipient of voltage or Reactive Power schedules. In Requirement R1, Part 1.1, the TOP must provide the system voltage schedule to the RC within 30 days of a request. If there is a reliability need for the TOP to provide the RC with the voltage and Reactive Power Schedule when notifying the Generator Operator, Requirement R5 should include how the RC obtains the voltage and Reactive Power schedule. Industry comments reveal that IRO-010-2 addresses this concern.

11. **Functional Model**: Are the correct functional entities assigned to perform the requirements consistent with the Functional Model?
   - Yes
   - ☐ No
   
   **If not, please summarize your assessment:**

12. **Applicability**: Is there a technical justification for revising the Applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?
   - ☐ Yes
   - ☑ No
   
   **If so, please summarize your assessment:**

13. **Reliability Gaps**: Are the appropriate actions for which there should be accountability included, or is there a gap?
   - ☑ Yes
   - ☐ No
   
   **If a gap is identified, please explain:**

14. **Technical Quality**: Does the Reliability Standard have a technical basis in engineering and operations?
15. Does the Reliability Standard reflect a higher solution than the lowest common denominator?

☒ Yes
☐ No

If not, please summarize your assessment:

16. Related Regional Reliability Standards: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide standard?

☒ Yes
☐ No

If yes, please identify the regional standard(s) and summarize your assessment:

1.) The Western Electricity Coordinating Council (WECC) region should consider whether VAR-002-WECC-2 (Automatic Voltage Regulators (AVR)) should be retired in light of the most recent versions of VAR-001-4.1 and VAR-002-4 which require all AVRs to be in service and in voltage control mode unless exempted by the TOP based on identified criteria.

2.) In VAR-001-4.1, Requirement R5 has no requirement to identify the “initial” status of the PSS. However, VAR-002-4 Requirement R3 requires the Generator Operator to notify the Transmission Operator of a power system stabilizer (PSS) status change. The initial status of the PSS should be clarified within the notification required by Requirement R5. The status of the PSS raises the question whether any of the VAR-501-WECC-2 (Power System Stabilizer), or any subsequent new version, PSS requirements should be established similar to AVR requirements for inclusion of the continent-wide standards. Industry comments affirm that it is not necessary to require notification of the initial state of the PSS as regional practices, interconnection agreements, and data specifications can address the initial state of the PSS.

3.) The WECC variance E.A.18 is specific to external control loops to the manufacturer’s AVR control loop. Due to the system configuration of the WECC, it was one of the earlier adopters of AVR and PSS controls. Due to the age of the controls or difficulty with setting reactive droop compensation on some older style controls, external loop controls were implemented from the plant control system. This can be done via DCS or SCADA. Variance E.A.18 requires that if external controls are used, that they do not affect the AVR’s transient response during
fault conditions. Industry comments did not reveal any reliability related need to address external control loops within the continent-wide Reliability Standard. Comments identified MOD-025 or MOD-026 as a more appropriate standard to address the need to document and communicate the impact of external control loop actions on the AVR to the TOP.

**RED, YELLOW, GREEN GRAZING**

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the standard through the standards development process for retirement or revision. The reasons for the Review Team’s conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.
Recommendation
The answers to the questions above, along with its Red, Yellow, or Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which, will be presented to the SC.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ RE-AFFIRM (This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN

☒ REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW

☐ REVISE (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED

☐ RETIRE (Would include retirement of associated RSAW.) RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR):

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ RE-AFFIRM (This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN

☒ REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW

☐ REVISE (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED

☐ RETIRE (Would include retirement of associated RSAW.) RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR):

Date submitted to Standards Committee: June 14, 2017
Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, “Acceptance Criteria of a Reliability Standard.”

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?
Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC’s reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.
Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts. Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

**Criterion A (Overarching Criterion)**
The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines “reliable operation” as: “… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

**Criteria B (Identifying Criteria)**

**B1. Administrative**
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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7 In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.
B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (e.g., plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.
This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

**B7. Redundant**
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (e.g., Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

**Criteria C (Additional data and reference points)**
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

**C1. Was the Reliability Standard requirement part of a FFT filing?**
The application of this criterion involves determining whether the requirement was included in a FFT filing.

**C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?**
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

**C3. What is the VRF of the Reliability Standard requirement?**
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that
it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC’s published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks.
(footnote omitted)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.
Attachment 3: Independent Expert Evaluation Process

Figure 1: Evaluation Flow Chart
Attachment 4: Potential Errata
Revisions/Corrections

The periodic review team has consolidated a number of errata and minor errors that could be cleaned up by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81 (None)

2. Clarity

2.1. There is a grammatical error in the first sentence of VAR-001, Requirement R4 in which the word "from:" should be moved after the "1) following..." to read "1) from following..." as shown below:

R4. The Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications.

2.2. This item was moved to Attachment 5.

2.3. Measure M1 should use the term “calendar” like the requirement.

2.4. Measure M5 uses the capitalized term "Reactive Power Schedule" that is not a glossary term. "Reactive Power" is a defined term. Lowercase the word "schedule."

2.5. Requirement E.A.18 (i.e., WECC Variance) uses the capitalized term "Automatic Voltage Regulators" that is not a glossary term. Lowercase the capitalized term "Automatic Voltage Regulators."

2.6. The Guidelines and Technical Basis, Rationale for R1, section should lowercase the capitalized term "Voltage Stability Ratings." This term was incorrectly capitalized in the Glossary definition of System Operating Limit (SOL) and was corrected as part of Project 2015-04 Alignment of Terms in 2016.

2.7. The Guidelines and Technical Basis, Rationale for R1 section should lowercase the capitalized term "post-Contingency Voltage Limits." This term was incorrectly capitalized in the Glossary definition of System Operating Limit (SOL) and was corrected to “post-Contingency voltage limits” as part of Project 2015-04 Alignment of Terms in 2016.

2.8. The Guidelines and Technical Basis, Rationale for R5 section, if retained, use lowercase "Voltage Schedule" because it is not a defined glossary term. If defined in the future, ensure consistency within the standard.
2.9. Use the format of "Mvar" rather than "MVAR" for Mega-voltampere reactive to be consistent with the IEEE designation throughout VAR-001. Spell out the first occurrence.

2.10. This item was moved to Attachment 5.

3. Definitions (None)

4. Compliance Elements

4.1. Requirement R1 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.2. Requirement R2 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.3. Requirement R3 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.4. This item was moved to Attachment 5.

4.5. Measure M2 incorrectly states the Time Horizon of “Operational Planning” and it should be “Operations Planning.” Correct this inconsistency.

4.6. Measure M3 has “may include,” but not the full phrase “may include, but is not limited to…” Add the additional verbiage for completeness.

4.7. The sentence construction of VAR-001-4.1 Measure M4 is incorrect and should be updated for correctness. The word “from:" should be moved to “1) from following…”

4.8. Requirement R4 should lead off with “Each Transmission Operator...” to be consistent with other Requirements and Measures.

5. Consistency with other Reliability Standards (None)

6. Changes Technology, System Conditions, or other Factors (None)

7. Practicable (None)

8. Consideration of Generator and Transmission Interconnection Facilities (None)

9. Results-Based Standard (RBS) (None)

10. Technical accuracy (None)

11. Functional Model (None)

12. Applicability (None)

13. Reliability Gaps (None)
14. Technical Quality (None)

15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16. Related Regional Reliability Standards (None)
Attachment 5: Other Miscellaneous Corrections/ Revisions

The periodic review team has consolidated a number of observations here that could be considered by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81

1.1. The second part of VAR-001-4.1, Requirement R5, Part 5.1 (i.e., "and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).") appears redundant with VAR-002-4, Requirement R1 and could be retired.

**Background:** The periodic review team recognizes that an automatic voltage regulator or "AVR" has several different operating modes, one being constant voltage, and another being constant reactive output. The requirement to operate with the AVR in the automatic mode is the driver of the requirement. The Transmission Operator should have flexibility to direct either voltage or reactive control at a specified voltage point (i.e., AVR in automatic). This issue would go away if the second part of VAR-001-4.1, Requirement R5.1 (i.e., "and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).") is removed from VAR-001-4.1, Requirement R5.1.

2. Clarity

2.1. VAR-001-4.1, Requirement R6 implies the consultation is a performance of the requirement (see Measure M6) due to the construction of the Requirement leading off with "After consultation with the Generator Owner...". Re-structure the Requirement to show the consultation a part of the performance to align with the Measures “...and that it consulted with the Generator Owner” or another equally effective option to eliminate the ambiguity.

2.2. VAR-001-4.1, Requirement R4 does not provide clarity on how the exemption criteria developed (e.g., blanket or specific). This applies to the voltage schedule and/or Reactive Power schedule in VAR-001, Requirement R5. Additional clarity on how the exemption criteria is developed in Requirement R4 could be helpful. For example, whether it is a blanket exemption or specific to certain generating units. Additionally, if a Generator Operator is unable to meet its voltage schedule, how would an exemption be applied where a small generator is trying to control voltage when another large generator is driving Mvar flow? How would this work in the case where the Transmission Operator has determined that there will be no criteria for exemption under Requirement R4? Industry comments affirm that clarity could be improved; however, two comments noted that there is no need to address.
2.3. Some entities are evaluating dynamic voltage schedules developed in the next-day or Real-time environment. As written the standard provides a Transmission Operator the flexibility to develop a voltage schedule that encompasses whatever time period and operating parameters that are appropriate. If VAR-001-4.1, Requirement R5 is revised in the future, edits should preserve the flexibility to allow for specifying the schedule in both Real-time and day-ahead.

2.4. When implementing a voltage schedule, the Transmission Operator needs to coordinate and be cognizant of the system response due to a change of any generator’s voltage schedule. VAR-001-4.1, Requirement R5 should consider additional clarity (could be addressed in the Guidelines and Technical Basis section) around coordination of implementing the voltage schedules so that they are not all implemented at the same point in time (e.g., seasonal, time of day based, Voltage schedules for multiple generators).

2.5. There is inconsistency between VAR-001-4.1, Requirement R1 and Requirement R5 to clarify that the system voltage schedule in Requirement R1 may be the same schedule or at the same points in the system as that of Requirement R5, where one "schedule" may be derived and used for both requirements (e.g., The "system" schedule may be identified to be at the high-side of the generator step-up unit transformers only). Requirement R5 uses “voltage schedule” and “Reactive Power schedule,” but only [system] voltage schedule is used in Requirement R1. Consider the need to include “Reactive Power schedule” in Requirement R1. The language should also retain flexibility so that Requirement R1 can be the same or different points in the system as Requirement R5.

2.6. Insert the word "calendar" between "30 days" for VAR-001-4.1, Requirement R5, Part 5.3 to be consistent with other uses within the standard and the Measure.

2.7. VAR-001-4.1, Requirement R6 should have the term “necessary” removed as it is superfluous.

3. Definitions

3.1. Defining the following terms “generator voltage schedule” and “generator Reactive Power schedule,” “system voltage schedule,” and “automatic voltage regulator (AVR)” (could be technology specific) may improve clarity. If so, review the Reliability Guideline: “Reactive Power Planning” section to determine if the Application Guideline in the standard provides clarity or at a minimum is consistent with the Reliability Guideline.

4. Compliance Elements

4.1. Measure M2 uses “resources based on their assessments of the system” as a measure for performance not required by the requirement. The clause "based on their assessments of the system" should be removed from the measure or added to the requirement to be consistent.

4.2. Measure M2: "For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled" is all inclusive. Reword the measure to conform to the requirement. For example, evidence may include..."
4.3. Measure M3 does not include "or direct" in the language. Revise the Measure to be consistent (i.e., direct or instruct, if changed according to other recommendations herein).

4.4. Section C1.2, Evidence Retention is silent on the Generator Operator (within the WECC Region), which is an applicable functional entity in the standard. The evidence retention section should provide minimum periods for all applicable entities listed in the standard.

4.5. The VSL in Requirement R5 does not make the distinction (e.g., High uses "all" and Severe use "any") as to the number of missed notifications, but the Measure M5 uses "applicable" which gives guidance that the requirement is implicitly not including exempt Generator Operators.

4.6. The second portion of the Severe VSL for Requirement R5 VSL language may need a High VSL component to address the notification component of the requirement for deviations.

4.7. The VSL for Requirement R5 needs to replace “does” (present tense) with “did” (past tense). VSLs are based on what happened in the past.

4.8. Requirement R4 may need to include Real-time Operations Time Horizon. It is practical that this exemption could be issued in Real-time.

4.9. Some entities are evaluating dynamic voltage schedules developed in the next-day or Real-time environment. If implementing Real-time or close to Real-time voltage scheduling a Transmission Operator would need to provide the required clarity. VAR-001-4.1 Requirement R5 may need to include the Real-time Operation Time Horizon.

4.10 Requirement R3 Time Horizons of Same-day Operations and Operational Planning are inappropriate. The requirement states "shall operate or direct the Real-time operation of devices", which would imply a Time Horizon of “Real-time Operations.” Therefore, replace the time horizons of Same-day Operations and Operations Planning with “Real-time Operations.”

5. Consistency with other Reliability Standards

5.1. VAR-001-4.1, Requirement R1 should include an additional clarifier to "adjacent" such as "within an Interconnection" or similar which could add clarity that voltage schedules for asynchronously adjacent Transmission Operators across a DC tie do not need to provide voltage schedules to one another. Voltage output on each side of the DC tie is controlled by the DC tie operator (e.g., language in COM-001-2).

5.2. Requirements R3 and R5.1 use the term “instruct” in lieu of “direct” to align more closely with more recent changes in IRO/TOP.COM standards which replaced the term “directive” with “Operating Instruction.”

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8 Time Horizons are used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time. [http://www.nerc.com/files/Time_Horizons.pdf](http://www.nerc.com/files/Time_Horizons.pdf)
5.3. There are cases, primarily for non-U.S. entities, for which the Transmission Owner (TO) owns the generator step-up (GSU) transformer. Requirement R6 properly identifies the Generator Owner functional entity, but does not include the TO that owns the GSU transformer. The requirement should include the TO in order to address those cases where the TO owns GSUs transformer.

6. Changes Technology, System Conditions, or other Factors (None)

7. Practicable (None)

8. Consideration of Generator and Transmission Interconnection Facilities (None)

9. Results-Based Standard (RBS)

   9.1. Requirement R6 is not results-based and should be evaluated whether it can be restructured. For example, the requirement lists “how” to accomplish the goal of providing tap changes to the Generator Owner rather the specifically identifying “what” is required by the Transmission Operator (See also Attachment 6, Item 2.1).

10. Technical accuracy (None)

11. Functional Model (None)

12. Applicability (None)

13. Reliability Gaps (None)

14. Technical Quality (None)

15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16. Related Regional Reliability Standards (None)
Periodic Review Recommendations: VAR-002-4 - Generator Operation for Maintaining Network Voltage Schedules
May 19, 2017

Executive Summary
The periodic review team completed a comprehensive review of VAR-002-4 – Generator Operation for Maintaining Network Voltage Schedules. The team found the standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue. Industry comments also affirmed that the standard: 1) is sufficient to protect reliability, 2) meets the reliability objective of the standard, and 3) no immediate revision is necessary. The following are the observations and recommendations of the periodic review team.

Introduction
The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute (ANSI) as an American National Standard.1 The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team, which is appointed annually by the Standards Committee (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM),2 the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (SME) team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.

Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the standard(s) by the Review Team, and document the Review Team’s

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considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input, as required by Section 13 of the NERC SPM.

### Review Team Composition

<table>
<thead>
<tr>
<th>Non-CIP Standards</th>
<th>Standing Review Team</th>
<th>Plus Section 13 (SMEs):</th>
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<tbody>
<tr>
<td></td>
<td>Chairs of the following NERC Standing Committees³:</td>
<td>The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.</td>
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<td>• SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)⁴</td>
<td></td>
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<tr>
<td></td>
<td>• Planning Committee</td>
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<td>• Operating Committee</td>
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<td></td>
<td>A regional representative will be included on the Standing Review Team.</td>
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<td></td>
<td>The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.</td>
<td></td>
</tr>
<tr>
<td>CIP Standards</td>
<td>Chairs of the following NERC Standing Committees⁵:</td>
<td>The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.</td>
</tr>
<tr>
<td></td>
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<td></td>
<td>• CIPC</td>
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³Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

⁴The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team’s review of a standard(s), and another SC member to chair a review of another standard(s).

⁵Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.
The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend re-affirming the standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard; however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to, or a retirement of, the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Scott Barfield-McGinnis via email or by telephone at 404-446-9689.

<table>
<thead>
<tr>
<th>Applicable Reliability Standard: VAR-001-4.1 &amp; VAR-002-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Team Members (include name and organization):</td>
</tr>
<tr>
<td>1. Stephen Solis (Chair), Electric Reliability Council of Texas, Inc.</td>
</tr>
<tr>
<td>2. Dennis Sauriol (Vice Chair), American Electric Power</td>
</tr>
<tr>
<td>3. Alex Chua, Pacific Gas and Electric</td>
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<td>4. Kevin Harrison, ITC Holdings</td>
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<td>5. Bill Harm, PJM Interconnection, LLC</td>
</tr>
<tr>
<td>6. Tim Kucey, PSEG Fossil, LLC</td>
</tr>
</tbody>
</table>

Date Review Completed: May 19, 2017

**Background Information** *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? *(If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*
   - [ ] Yes
   - [x] No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? *(If there are, NERC*
staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard.)

☐ Yes
☒ No

Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes
☒ No

Please explain:

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes
☐ No

Please explain:

Questions for the Review Team
If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff, as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

1. Quality

1. Reliability Need, Paragraph 81: Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use Attachment 2: Paragraph 81 Criteria to make this determination.

☐ Yes
☒ No

Please summarize your application of Paragraph 81 Criteria, if any:
2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obvious ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements inconsistent with the purpose of the Reliability Standard?
   d. Are the requirements not stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard incomplete and not self-contained?
   f. Does the Reliability Standard use inconsistent terminology?

   □ Yes  ☑ No

**Please summarize your assessment:**

Requirement R2, Part 2.3 is prescriptive and not performance based. It is not clear whether a methodology is required or equipment. The phrase "existing equipment" in Measure M2 causes this confusion. The phrase should be removed to eliminate an implied requirement or revise the requirement to be explicit.

Additionally, in the main part of Measure M2 the first sentence of the measure (“In order to identify when a generator is deviating from its schedule, the Generator Operator will monitor voltage based on existing equipment at its Facility.”) implies a performance (i.e., monitoring) that is not required, but implicit. This sentence should be revised to remove the inference and moved to Part 2.3 of the measure to align with the requirement.

Industry comments affirm that Requirement R2, Part 2.3 should be considered for removal or modification to be a results-based (performance, competency, or risk based) standard.

3. **Definitions:** Do any of the defined terms used within the Reliability Standard need to be refined?

   □ Yes  ☑ No

**Please explain:**

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons)
consistent with the direction of the Reliability Assurance Initiative (RAI) and FERC and NERC guidelines?

☑ Yes
☐ No

If you answered “No,” please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards**: Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

☐ Yes
☒ No

If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors**: Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

☐ Yes
☒ No

If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

☐ Yes
☒ No

b. Is there a concern that it is not cost effective as drafted?

☐ Yes
☒ No

Please summarize your assessment of the practicability of the standard:
8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator Interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard?

- Yes
- No

*Guiding Questions:*

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

*Response: There is no ambiguity about the inclusion of generator Interconnection Facilities.*

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

*Response: Not applicable.*

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

*Response: Not applicable.*

9. **Results-Based Standard (RBS):** Is the Reliability Standard drafted as a RBS?

- Yes
- No

*If not, please summarize your assessment:*

*Guiding Questions:*

a. Does the Reliability Standard address performance, risk (prevention) and capability?
b. Does the Reliability Standard follow the RBS format (for example, requirement and part structure) in Attachment 1?

☐ Yes
☐ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard\(^6\)?

☐ Yes
☐ No

II. Content

10. **Technical accuracy**: Is the content of the requirements technically correct, including identifying who does what and when?

☐ Yes
☐ No

If not, please summarize your assessment:

11. **Functional Model**: Are the correct functional entities assigned to perform the requirements consistent with the Functional Model?

☐ Yes
☐ No

If not, please summarize your assessment:

12. **Applicability**: Is there a technical justification for revising the Applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

\(^6\) Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of:

☐ Yes
☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

☐ Yes
☒ No

If a gap is identified, please explain:

Requirement R3, does not identify the Reliability Coordinator (RC) to be included in notifications. A clarification on how the RC might receive automatic voltage regulator (AVR) notifications may be important as the AVR status could impact a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) value. This may be addressed by a revision VAR-001-4, alternative guidance, or existing requirements (e.g., IRO-010-2 – *Reliability Coordinator Data Specification and Collection* as the method for acquiring necessary notifications). Industry comments affirm that IRO-010-2 provides the method for the RC to acquire the status of the AVR.

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes
☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☑ Yes
☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards:** Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide standard?
☐ Yes
☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

Maintain awareness on the potential impact to VAR-002-4 since the WECC region is considering retirement or revisions to VAR-002-WECC-2.
**RED, YELLOW, GREEN GRADING**

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow – is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the standard through the standards development process for retirement or revision. The reasons for the Review Team’s conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow, or Red.
Recommendation

The answers to the questions above, along with its Red, Yellow, or Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which, will be presented to the SC.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ RE-AFFIRM (This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN

☑ REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW

☐ REVISE (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED

☐ RETIRE (Would include retirement of associated RSAW.) RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR):

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ RE-AFFIRM (This should be checked only if there are no outstanding directives, Interpretations or issues identified by stakeholders.) GREEN

☑ REVISE (The standard is sufficient to protect reliability and meet the reliability objective of the standard; however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue.) (Would include revision of associated RSAW.) YELLOW

☐ REVISE (The recommended revisions are required to support reliability.) (Would include revision of associated RSAW.) RED

☐ RETIRE (Would include retirement of associated RSAW.) RED

Technical Justification (If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR):

Date submitted to Standards Committee: June 14, 2017
Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, “Acceptance Criteria of a Reliability Standard.”

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?
Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC’s reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.
Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts. Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)
The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines “reliable operation” as: “... operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

Criteria B (Identifying Criteria)
B1. Administrative
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

7 In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.
B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC’s rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (e.g., plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (e.g., annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.
This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

**B7. Redundant**
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (e.g., Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

**Criteria C (Additional data and reference points)**
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

**C1. Was the Reliability Standard requirement part of a FFT filing?**
The application of this criterion involves determining whether the requirement was included in a FFT filing.

**C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?**
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

**C3. What is the VRF of the Reliability Standard requirement?**
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that
it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC’s published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.
Attachment 3: Independent Expert Evaluation Process

![Evaluation Flowchart]

Figure 1: Evaluation Flow Chart
Attachment 4: Potential Errata
Revisions/Corrections

The periodic review team has consolidated a number of errata and minor errors that could be cleaned by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81 (None)
2. Clarity
   2.1. Capitalize the term “reactive power” in Footnote 4. It uses the lowercase term "reactive power." The term Reactive Power\(^8\) is a NERC defined term and therefore should be capitalized.
   2.2. This item was moved to Attachment 5.
   2.3. This item was moved to Attachment 5.
   2.4. This item was moved to Attachment 5.
   2.5. This item was moved to Attachment 5.
   2.6. This item was moved to Attachment 5.
   2.7. This item was moved to Attachment 5.
3. Definitions (None)
4. Compliance Elements (None)
5. Consistency with Other Reliability Standards (None)
6. Changes in Technology, System Conditions, or other Factors (None)
7. Practicable (None)
8. Consideration of Generator and Transmission Interconnection Facilities (None)
9. Results-Based Standard (RBS) (None) (None)
10. Technical accuracy (None)
11. Functional Model (None)
12. Applicability (None)
13. Reliability Gaps (None)

\(^8\) Ibid.
14. Technical Quality (None)

15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16. Related Regional Reliability Standards (None)
Attachment 5: Other Miscellaneous Corrections/Revisions

The periodic review team has consolidated a number of observations here that could be considered by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81 (None)

2. Clarity

2.1. Requirement R2, Part 2.3 has the clause “specified by the Transmission Operator” which is unnecessary and may introduce confusion with respect to whether it is referring to the voltage schedule or the methodology. Remove this phrase or reword to avoid confusion.

2.2. Requirement R6 uses the term "equipment rating." Equipment Rating is a NERC defined term. Requirement R6 should be updated to reflect the defined term "Equipment Rating" or “rating” should be removed to be consistent with other standard (e.g., TOP-001-3, Requirements R3 and R5).

2.3. Requirement R4 is silent on the magnitude or quantity of “change in reactive capability” (e.g. 1 MVAR or 100 MVAR). Requirement R4 should be reviewed for potential improvements in establishing the level of change that triggers “change in reactive capability” or where that level of change would be identified.

2.4. In Requirement R3, clarify that the Generator Operator shall provide notification to the Transmission Operator that is mutually agreeable to the Transmission Operator. This would clarify which medium is available or unavailable for Generator Operator to use for notification, which will avoid the Requirement from prescribing the method (e.g., phone call, telemetry, email, etc.).

2.5. Requirement R4 concerning reactive capability is based on the “D” Curve, which is a snapshot; therefore, the notification component is for degradation or restoration from the degradation, not additional capability due to other factors. Revise the current Requirement R4 language for clarity (i.e., “change in reactive capability”)

2.6. Revise Requirement R4 to add clarity that a full “D” Curve (i.e., restatement of capabilities) is not required when Reactive Power output is affected.

2.7. In Requirement R4, visit whether criteria should be spelled out explicitly or "self-developed" for the term "status" in the main requirement.

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* Ibid.
2.8. In Requirement R4, the term "status" in the bulleted exception concerning dispersed generating resources (DGR) should be struck given the use of "status" is associated with Requirement R3 and not R4.

2.9. Requirement R4 refers to the Bulk Electric System (BES)\(^{10}\) definition in a manner that brings in applicability (exception) component of certain Generator Operators. To the extent possible, this exception be considered for inclusion in the Applicability section of the standard.

3. Definitions (None)

4. Compliance Elements (None)

4.1. In Requirement R5 the time horizon of Real-time Operations is inappropriate. Requirement R5 requires the Generator Owner (GO) to provide data to the Transmission Operator (TOP) and Transmission Planner (TP) within 30 calendar days of a request. Therefore, mitigating a violation of this requirement could never occur in Real-time Operations, but rather be the Operations Planning time horizon. The violation of this requirement should garner sanctions associated with a longer time horizon.

4.2. In Requirement R6, the time horizon of Real-time Operations is inappropriate. Requirement R6 requires that generator step-up (GSU) transformer tap changes be implemented by the Generator Owner, this will typically involve an outage of the GSU transformer and is the culmination of a longer term process to determine if a GSU transformer tap change is appropriate. The violation of this requirement should garner sanctions associated with a longer time horizon.

4.3. The Requirement R2 Violation Severity Level (VSL) High category does not note that the entity complied with maintaining the voltage or Reactive Power schedule, which must be achieved to have partial performance of the requirement. It is recommended to add an introductory phrase to the High VSL category stating: “The Generator Operator maintained the voltage or Reactive Power schedule, but did not...”.

4.4. The last sentence of Measure M1 should be clarified to make clear that the reference is referring to being exempted from automatic voltage control mode and not voltage schedule.

5. Consistency with Other Reliability Standards (None)

6. Changes in Technology, System Conditions, or other Factors (None)

6.1. Requirement R5, Part 5.1.x may not be technology neutral with respect to transformer modeling data because of the use of “fixed tap ranges.” Revise the requirement to ensure that it is technology neutral and inclusive of load tap changing (LTC) transformers.

7. Practicable (None)

8. Consideration of Generator and Transmission Interconnection Facilities (None)

9. Results-Based Standard (RBS) (None) (None)

10. Technical accuracy (None)

10.1. In Requirement R1 dispersed generation resources (DGR) can be comprised of numerous generators. Each generator may have its own automatic voltage regulator (AVR) in addition to a site AVR that coordinates the voltage level of each of the distributed generators to regulate voltage at a common point such as the GSU transformer. Reword the requirement by replacing "generator" with "generator or DGR site AVR."

10.2. In Requirement R2 typical dispersed generation resources (DGR) have a site automatic voltage regulator (AVR) that coordinates the voltage of all generators to a common regulation point. If this site AVR fails each generator will typically either continue to regulate at the last known set point or revert to unity power factor. If the site AVR fails the Generator Owner should report a change per Requirement R3. Augment the requirement to accommodate these circumstances without a violation.

11. Functional Model (None)

12. Applicability (None)

13. Reliability Gaps (None)

14. Technical Quality (None)

14.1. Requirement R5, does not identify the Transmission Owner (TO) for cases where the TO owns the generator step-up transformer. Revise Requirement R6 to require the TO to communicate settings to the Transmission Operator.

14.2. Requirement R3 require the Generator Operator to notify the Transmission Operator of power system stabilizer (PSS) unavailability. The operational requirements for initial state of PSS (on/off) clarity need to be assessed for inclusion within the VAR suite of standards (including expectations for startup, shutdown, or testing mode). Consider whether new requirements or alternative guidance is needed to identify the expected initial state for a PSS.

15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)

16. Related Regional Reliability Standards (None)

16.1. The standard does not address any specific power system stabilizer (PSS) requirements. Consider including PSS requirements in the VAR standard(s) similar to PSS requirements in VAR-501-WECC-2 (or any subsequent new version), if there is a reliability need.
Project 2016-EPR-02 Errata of VAR-001-4.1 and VAR-002-4

Action
Approve the errata revisions based on the recommendations of the periodic review team (PRT) review of Reliability Standards VAR-001-4.1 (Voltage and Reactive Control) and VAR-002-4 (Generator Operation for Maintaining Network Voltage Schedules).

Background
The NERC Standard Processes Manual Section 12.0: Process for Correcting Errata states:

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

The PRT completed its comprehensive review of VAR-001-4.1 and VAR-002-4 on May 19, 2017, which included feedback received from industry. The team found the standards are sufficient to protect reliability and meet the reliability objective of the standards; however, there may be future opportunity to improve non-substantive or insignificant quality and content issues. Industry comments also affirmed that the standards: 1. are sufficient to protect reliability, 2. meet the reliability objective of the standards, and 3. no immediate revision is necessary. However, the PRT identified various errata corrections that could be made to the currently enforceable VAR-001-4.1 and VAR-002-4 Reliability Standards. The proposed errata changes consist of changes to correct grammar and capitalization of defined terms (see the associated recommendations at Attachment 4.) The proposed errata do not change the scope or intent of the associated Reliability Standards, and have no material impact on the end users of the Reliability Standards.
A. Introduction

1. **Title:** Voltage and Reactive Control
2. **Number:** VAR-001-4.2
3. **Purpose:** To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators
   - **4.2.** Generator Operators within the Western Interconnection (for the WECC Variance)
5. **Effective Date:**
   - **5.1.** The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operations Planning]

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. Each Transmission Operator shall specify the criteria that will exempt generators: 1) from following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

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

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.

For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt: 1) from following a voltage or Reactive Power schedule, 2) from having its
automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator’s discretion. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.
C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None
## Table of Compliance Elements

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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</thead>
<tbody>
<tr>
<td>R1</td>
<td>Operations Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).</td>
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<td>R2</td>
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<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.</td>
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<tr>
<td>R3</td>
<td>Real-time Operations, Same-day Operations, and Operations Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL.</td>
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<tr>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.</td>
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<tr>
<td>R #</td>
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<td>R4</td>
<td>Operations Planning</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
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<td>Moderate VSL</td>
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<td>R5</td>
<td>Operations Planning</td>
<td>Medium</td>
<td>N/A</td>
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<td>The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.</td>
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<td></td>
<td>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators.</td>
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<td>Or</td>
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<td></td>
<td>The Transmission Operator does not provide the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels</td>
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<td></td>
<td></td>
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<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
</tr>
<tr>
<td>R6</td>
<td>Operations Planning</td>
<td>Lower</td>
<td>The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.</td>
</tr>
</tbody>
</table>
D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the automatic voltage regulators (AVR) to manage Mvar loading: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

E.A.18.1. Each control loop’s design incorporates the AVR’s automatic voltage controlled response to voltage deviations during System Disturbances.

E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.
Measures

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage Mvar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

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1 The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.
# Violation Severity Levels

<table>
<thead>
<tr>
<th>E #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>E.A.13</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
</tr>
<tr>
<td>E.A.14</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.</td>
</tr>
<tr>
<td>E.A.15</td>
<td>The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.</td>
</tr>
<tr>
<td>E #</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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</tr>
<tr>
<td>E.A.16</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.</td>
<td>The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.</td>
</tr>
<tr>
<td>E.A.17</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Generator Operator.</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator. Operator.</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator. Operator.</td>
<td>The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.</td>
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<tr>
<td>E.A.18</td>
<td>N/A</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
</tr>
</tbody>
</table>

E. Interpretations

None
F. Associated Documents

None.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>1</td>
<td>August 2, 2006</td>
<td>BOT Adoption</td>
<td>Revised</td>
</tr>
<tr>
<td>1</td>
<td>June 18, 2007</td>
<td>FERC approved Version 1 of the standard.</td>
<td>Revised</td>
</tr>
<tr>
<td>1</td>
<td>July 3, 2007</td>
<td>Added “Generator Owners” and “Generator Operators” to Applicability section.</td>
<td>Errata</td>
</tr>
<tr>
<td>1</td>
<td>August 23, 2007</td>
<td>Removed “Generator Owners” and “Generator Operators” to Applicability section.</td>
<td>Errata</td>
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<tr>
<td>2</td>
<td>August 5, 2010</td>
<td>Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.</td>
<td>Revised</td>
</tr>
<tr>
<td>2</td>
<td>January, 10 2011</td>
<td>FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>May 9, 2012</td>
<td>Adopted by NERC Board of Trustees; Modified to add a WECC region variance</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>June 20, 2013</td>
<td>FERC issued order approving VAR-001-3</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>November 21, 2013</td>
<td>R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)</td>
<td>Revised</td>
</tr>
<tr>
<td>4</td>
<td>February 6, 2014</td>
<td>Adopted by NERC Board of Trustees</td>
<td>Revised</td>
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<td>4</td>
<td>August 1, 2014</td>
<td>FERC issued letter order approved approving VAR-001-4</td>
<td>Revised</td>
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<tr>
<td>4.1</td>
<td>August 25, 2015</td>
<td>Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power</td>
<td>Errata</td>
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<tr>
<td>4.1</td>
<td>November 13, 2015</td>
<td>FERC Letter Order approved errata to VAR-001-4.1, Docket RD15-6-000</td>
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<td>4.2</td>
<td>June 14, 2017</td>
<td>Project 2016-EPR-02 errata recommendations</td>
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</table>
Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) voltage stability ratings (Applicable pre- and post-Contingency Voltage Stability) and 2) System Voltage Limits (Applicable pre- and post-Contingency voltage limits). Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC’s directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific
area’s needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP’s criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

**Rationale for R5:**

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a “tolerance band” as specified in the voltage schedule and the control dead-band in the generator’s excitation system.

Voltage schedule tolerances are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator’s facility during normal operations, and be based on the TOP’s assessment of N-1 and credible N-2 system contingencies. The voltage schedule’s bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator’s automatic voltage regulator’s control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule’s bandwidth.

**Rationale for R6:**

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.
A. Introduction

1. Title: Voltage and Reactive Control

2. Number: VAR-001-4.12

3. Purpose: To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in Real-time to protect equipment and the reliable operation of the Interconnection.

4. Applicability:
   4.1. Transmission Operators
   4.2. Generator Operators within the Western Interconnection (for the WECC Variance)

5. Effective Date:
   5.1. The standard shall become effective on the first day of the first calendar quarter after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.
B. Requirements and Measures

R1. Each Transmission Operator shall specify a system voltage schedule (which is either a range or a target value with an associated tolerance band) as part of its plan to operate within System Operating Limits and Interconnection Reliability Operating Limits. [Violation Risk Factor: High] [Time Horizon: Operational Operations Planning]

1.1. Each Transmission Operator shall provide a copy of the voltage schedules (which is either a range or a target value with an associated tolerance band) to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request.

M1. The Transmission Operator shall have evidence that it specified system voltage schedules using either a range or a target value with an associated tolerance band.

For part 1.1, the Transmission Operator shall have evidence that the voltage schedules (which is either a range or a target value with an associated tolerance band) were provided to its Reliability Coordinator and adjacent Transmission Operators within 30 calendar days of a request. Evidence may include, but is not limited to, emails, website postings, and meeting minutes.

R2. Each Transmission Operator shall schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. Transmission Operators can provide sufficient reactive resources through various means including, but not limited to, reactive generation scheduling, transmission line and reactive resource switching, and using controllable load. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Operations Planning]

M2. Each Transmission Operator shall have evidence of scheduling sufficient reactive resources based on their assessments of the system. For the operational operations planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled.

R3. Each Transmission Operator shall operate or direct the Real-time operation of devices to regulate transmission voltage and reactive flow as necessary. [Violation Risk Factor: High] [Time Horizon: Real-time Operations, Same-day Operations, and Operational Operations Planning]

M3. Each Transmission Operator shall have evidence that actions were taken to operate capacitive and inductive resources as necessary in Real-time. This may include, but is not limited to, instructions to Generator Operators to: 1) provide additional voltage support; 2) bring resources on-line; or 3) make manual adjustments.

R4. The Each Transmission Operator shall specify the criteria that will exempt generators from: 1) following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

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

M4. Each Transmission Operator shall have evidence of the documented criteria for generator exemptions.
For part 4.1, the Transmission Operator shall also have evidence to show that, for each generator in its area that is exempt from: 1) following a voltage or Reactive Power schedule, 2) having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any notifications, the associated Generator Operator was notified of this exemption.

R5. Each Transmission Operator shall specify a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) at either the high voltage side or low voltage side of the generator step-up transformer at the Transmission Operator’s discretion. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

5.1. The Transmission Operator shall provide the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).

5.2. The Transmission Operator shall provide the Generator Operator with the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band).

5.3. The Transmission Operator shall provide the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the Generator Operator within 30 days of receiving a request.

M5. The Transmission Operator shall have evidence of a documented voltage or Reactive Power Schedule (which is either a range or a target value with an associated tolerance band).

For part 5.1, the Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to the applicable Generator Operators, and that the Generator Operator was directed to comply with the schedule in automatic voltage control mode, unless exempted.

For part 5.2, the Transmission Operator shall have evidence it provided notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band). For part 5.3, the Transmission Operator shall have evidence it provided the criteria used to develop voltage schedules or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) within 30 days of receiving a request by a Generator Operator.

R6. After consultation with the Generator Owner regarding necessary step-up transformer tap changes and the implementation schedule, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

M6. The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit’s step-up transformer tap in accordance with the requirement and that it consulted with the Generator Owner.
C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Transmission Operator shall retain evidence for Measures M1 through M6 for 12 months. The Compliance Monitor shall retain any audit data for three years.

1.3. Compliance Monitoring and Assessment Processes:

“Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

1.4. Additional Compliance Information:

None
**Table of Compliance Elements**

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
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<th>Severe VSL</th>
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<tbody>
<tr>
<td>R1</td>
<td>Operational Operations Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not specify a system voltage schedule (which is either a range or a target value with an associated tolerance band).</td>
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<td>R2</td>
<td>Real-time Operations, Same-day Operations, and Operational Operations Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an SOL. The Transmission Operator does not schedule sufficient reactive resources as necessary to avoid violating an IROL.</td>
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<tr>
<td>R3</td>
<td>Real-time Operations, Same-day Operations, and Operational Operations Planning</td>
<td>High</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an SOL. The Transmission Operator does not operate or direct any real-time operation of devices as necessary to avoid violating an IROL.</td>
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<tr>
<td>R #</td>
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<tr>
<td>R4</td>
<td>Operations Planning</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Transmission Operator has exemption criteria and notified the Generator Operator, but the Transmission Operator does not have evidence of the notification to the Generator Operator.</td>
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<tr>
<td></td>
<td></td>
<td></td>
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<td></td>
<td>The Transmission Operator does not have exemption criteria.</td>
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<tr>
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<td>Time Horizon</td>
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<td>R5</td>
<td>Operations Planning</td>
<td>Medium</td>
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<td></td>
<td>The Transmission Operator does not provide the criteria for voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) after 30 days of a request.</td>
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<td>The Transmission Operator does not provide voltage or Reactive Power schedules (which is either a range or a target value with an associated tolerance band) to any Generator Operators. Or The Transmission Operator does not provide the notification requirements for deviations from the voltage or Reactive Power schedule (which is either a range or a target value with an associated tolerance band) to all Generator Operators.</td>
</tr>
<tr>
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<tr>
<td>R6</td>
<td>Operations Planning</td>
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<td>Severe VSL</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>The Transmission Operator does not provide either the technical justification or timeframe for changing generator step-up tap settings.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator does not provide the technical justification and the timeframe for changing generator step-up tap settings.</td>
</tr>
</tbody>
</table>
D. Regional Variances

The following Interconnection-wide variance shall be applicable in the Western Electricity Coordinating Council (WECC) and replaces, in their entirety, Requirements R4 and R5. Please note that Requirement R4 is deleted and R5 is replaced with the following requirements.

Requirements

E.A.13 Each Transmission Operator shall issue any one of the following types of voltage schedules to the Generator Operators for each of their generation resources that are on-line and part of the Bulk Electric System within the Transmission Operator Area: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

- A voltage set point with a voltage tolerance band and a specified period.
- An initial volt-ampere reactive output or initial power factor output with a voltage tolerance band for a specified period that the Generator Operator uses to establish a generator bus voltage set point.
- A voltage band for a specified period.

E.A.14 Each Transmission Operator shall provide one of the following voltage schedule reference points for each generation resource in its Area to the Generator Operator. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

- The generator terminals.
- The high side of the generator step-up transformer.
- The point of interconnection.
- A location designated by mutual agreement between the Transmission Operator and Generator Operator.

E.A.15 Each Generator Operator shall convert each voltage schedule specified in Requirement E.A.13 into the voltage set point for the generator excitation system. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same-day Operations]

E.A.16 Each Generator Operator shall provide its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals within 30 calendar days of request by its Transmission Operator. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

E.A.17 Each Transmission Operator shall provide to the Generator Operator, within 30 calendar days of a request for data by the Generator Operator, its transmission equipment data and operating data that supports development of the voltage set point conversion methodology. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

E.A.18 Each Generator Operator shall meet the following control loop specifications if the Generator Operator uses control loops external to the Automatic Voltage Regulators automatic voltage regulators (AVR) to manage MVar loading: [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

E.A.18.1. Each control loop’s design incorporates the AVR’s automatic voltage controlled response to voltage deviations during System Disturbances.
E.A.18.2. Each control loop is only used by mutual agreement between the Generator Operator and the Transmission Operator affected by the control loop.

Measures¹

M.E.A.13 Each Transmission Operator shall have and provide upon request, evidence that it provided the voltage schedules to the Generator Operator. Dated spreadsheets, reports, voice recordings, or other documentation containing the voltage schedule including set points, tolerance bands, and specified periods as required in Requirement E.A.13 are acceptable as evidence.

M.E.A.14 The Transmission Operator shall have and provide upon request, evidence that it provided one of the voltage schedule reference points in Requirement E.A.14 for each generation resource in its Area to the Generator Operator. Dated letters, e-mail, or other documentation that contains notification to the Generator Operator of the voltage schedule reference point for each generation resource are acceptable as evidence.

M.E.A.15 Each Generator Operator shall have and provide upon request, evidence that it converted a voltage schedule as described in Requirement E.A.13 into a voltage set point for the AVR. Dated spreadsheets, logs, reports, or other documentation are acceptable as evidence.

M.E.A.16 The Generator Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Transmission Operator it provided its voltage set point conversion methodology from the point in Requirement E.A.14 to the generator terminals. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.17 The Transmission Operator shall have and provide upon request, evidence that within 30 calendar days of request by its Generator Operator it provided data to support development of the voltage set point conversion methodology. Dated reports, spreadsheets, or other documentation are acceptable as evidence.

M.E.A.18 If the Generator Operator uses outside control loops to manage MVar loading, the Generator Operator shall have and provide upon request, evidence that it met the control loop specifications in sub-parts E.A.18.1 through E.A.18.2. Design specifications with identified agreed-upon control loops, system reports, or other dated documentation are acceptable as evidence.

¹ The number for each measure corresponds with the number for each requirement, i.e. M.E.A.13 means the measure for Requirement E.A.13.
Violation Severity Levels

<table>
<thead>
<tr>
<th>E #</th>
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<tbody>
<tr>
<td>E.A.13</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to at least one generation resource but less than or equal to 5% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 5% but less than or equal to 10% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 10% but less than or equal to 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
<td>For the specified period, the Transmission Operator did not issue one of the voltage schedules listed in E.A.13 to more than 15% of the generation resources that are on-line and part of the BES in the Transmission Operator Area.</td>
</tr>
<tr>
<td>E.A.14</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for at least one but less than or equal to 5% of the generation resources in the Transmission Operator area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 5% but less than or equal to 10% of the generation resources in the Transmission Operator Area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 10% but less than or equal to 15% of the generation resources in the Transmission Operator Area.</td>
<td>The Transmission Operator did not provide a voltage schedule reference point for more than 15% of the generation resources in the Transmission Operator Area.</td>
</tr>
<tr>
<td>E.A.15</td>
<td>The Generator Operator failed to convert at least one voltage schedule in Requirement E.A.13 into the voltage set point for the AVR for less than 25% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 25% or more but less than 50% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 50% or more but less than 75% of the voltage schedules.</td>
<td>The Generator Operator failed to convert the voltage schedules in Requirement E.A.13 into the voltage set point for the AVR for 75% or more of the voltage schedules.</td>
</tr>
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<tr>
<td>E.A.16</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Transmission Operator.</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Transmission Operator.</td>
<td>The Generator Operator provided its voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Transmission Operator.</td>
<td>The Generator Operator did not provide its voltage set point conversion methodology within 120 days of a request by the Transmission Operator.</td>
</tr>
<tr>
<td>E.A.17</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 30 days but less than or equal to 60 days of a request by the Generator Operator.</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 60 days but less than or equal to 90 days of a request by the Generator Operator.</td>
<td>The Transmission Operator provided its data to support development of the voltage set point conversion methodology greater than 90 days but less than or equal to 120 days of a request by the Generator Operator.</td>
<td>The Transmission Operator did not provide its data to support development of the voltage set point conversion methodology within 120 days of a request by the Generator Operator.</td>
</tr>
<tr>
<td>E.A.18</td>
<td>N/A</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.1 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
<td>The Generator Operator did not meet the control loop specifications in EA18.1 through EA18.2 when the Generator Operator uses control loop external to the AVR to manage Mvar loading.</td>
</tr>
</tbody>
</table>

E. Interpretations

None
F. Associated Documents

None.

Version History

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<td>August 23, 2007</td>
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<td>August 5, 2010</td>
<td>Adopted by NERC Board of Trustees; Modified to address Order No. 693 Directives contained in paragraphs 1858 and 1879.</td>
<td>Revised</td>
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<td>2</td>
<td>January 10, 2011</td>
<td>FERC issued letter order approving the addition of LSEs and Controllable Load to the standard.</td>
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<tr>
<td>3</td>
<td>June 20, 2013</td>
<td>FERC issued order approving VAR-001-3</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>November 21, 2013</td>
<td>R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)</td>
<td>Revised</td>
</tr>
<tr>
<td>4</td>
<td>February 6, 2014</td>
<td>Adopted by NERC Board of Trustees</td>
<td>Revised</td>
</tr>
<tr>
<td>4</td>
<td>August 1, 2014</td>
<td>FERC issued letter order issued approving VAR-001-4</td>
<td>Revised</td>
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<tr>
<td>4.1</td>
<td>August 25, 2015</td>
<td>Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power</td>
<td>Errata</td>
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<tr>
<td>4.1</td>
<td>November 13, 2015</td>
<td>FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000</td>
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<td>4.2</td>
<td>June 14, 2017</td>
<td>Project 2016-EPR-02 errata recommendations</td>
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</table>
VAR-001-4.2 Application Guidelines

Guidelines and Technical Basis

For technical basis for each requirement, please review the rationale provided for each requirement.

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:

Paragraph 1868 of Order No. 693 requires NERC to add more "detailed and definitive requirements on “established limits” and “sufficient reactive resources”, and identify acceptable margins (i.e. voltage and/or reactive power margins)." Since Order No. 693 was issued, however, several FAC and TOP standards have become enforceable to add more requirements around voltage limits. More specifically, FAC-011 and FAC-014 require that System Operating Limits (SOLs) and reliability margins are established. The NERC Glossary definition of SOLs includes both: 1) **Voltage Stability Ratings** *(Applicable pre- and post-Contingency Voltage Stability)* and 2) **System Voltage Limits** *(Applicable pre- and post-Contingency Voltage Limits)*. Therefore, for reliability reasons Requirement R1 now requires a Transmission Operator (TOP) to set voltage or Reactive Power schedules with associated tolerance bands. Further, since neighboring areas can affect each other greatly, each TOP must also provide a copy of these schedules to its Reliability Coordinator (RC) and adjacent TOP upon request.

Rationale for R2:

Paragraph 1875 from Order No. 693 directed NERC to include requirements to run voltage stability analysis periodically, using online techniques where commercially available and offline tools when online tools are not available. This standard does not explicitly require the periodic voltage stability analysis because such analysis would be performed pursuant to the SOL methodology developed under the FAC standards. TOP standards also require the TOP to operate within SOLs and Interconnection Reliability Operating Limits (IROL). The VAR standard drafting team (SDT) and industry participants also concluded that the best models and tools are the ones that have been proven and the standard should not add a requirement for a responsible entity to purchase new online simulations tools. Thus, the VAR SDT simplified the requirements to ensuring sufficient reactive resources are online or scheduled. Controllable load is specifically included to answer FERC's directive in Order No. 693 at Paragraph 1879.

Rationale for R3:

Similar to Requirement R2, the VAR SDT determined that for reliability purposes, the TOP must ensure sufficient voltage support is provided in Real-time in order to operate within an SOL.

Rationale for R4:

The VAR SDT received significant feedback on instances when a TOP would need the flexibility for defining exemptions for generators. These exemptions can be tailored as the TOP deems necessary for the specific
area’s needs. The goal of this requirement is to provide a TOP the ability to exempt a Generator Operator (GOP) from: 1) a voltage or Reactive Power schedule, 2) a setting on the AVR, or 3) any VAR-002 notifications based on the TOP’s criteria. Feedback from the industry detailed many system events that would require these types of exemptions which included, but are not limited to: 1) maintenance during shoulder months, 2) scenarios where two units are located within close proximity and both cannot be in voltage control mode, and 3) large system voltage swings where it would harm reliability if all GOP were to notify their respective TOP of deviations at one time. Also, in an effort to improve the requirement, the sub-requirements containing an exemption list were removed from the currently enforceable standard because this created more compliance issues with regard to how often the list would be updated and maintained.

**Rationale for R5:**

The new requirement provides transparency regarding the criteria used by the TOP to establish the voltage schedule. This requirement also provides a vehicle for the TOP to use appropriate granularity when setting notification requirements for deviation from the voltage or Reactive Power schedule. Additionally, this requirement provides clarity regarding a “tolerance band” as specified in the voltage schedule and the control dead-band in the generator’s excitation system.

Voltage **Schedule** **tolerances** are the bandwidth that accompanies the voltage target in a voltage schedule, should reflect the anticipated fluctuation in voltage at the Generation Operator’s facility during normal operations, and be based on the TOP’s assessment of N-1 and credible N-2 system contingencies. The voltage schedule’s bandwidth should not be confused with the control dead-band that is programmed into a Generation Operator’s automatic voltage regulator’s control system, which should be adjusting the AVR prior to reaching either end of the voltage schedule’s bandwidth.

**Rationale for R6:**

Although tap settings are first established prior to interconnection, this requirement could not be deleted because no other standard addresses when a tap setting must be adjusted. If the tap setting is not properly set, then the amount of VARs produced by a unit can be affected.

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<td>3</td>
<td>June 20, 2013</td>
<td>FERC issued order approving VAR-001-3.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>November 21, 2013</td>
<td>R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)</td>
<td>Revised</td>
</tr>
<tr>
<td>4</td>
<td>February 6, 2014</td>
<td>Adopted by NERC Board of Trustees</td>
<td>Revised</td>
</tr>
<tr>
<td>4</td>
<td>August 1, 2014</td>
<td>FERC issued letter order issued approving VAR-001-4.</td>
<td></td>
</tr>
<tr>
<td>4.1</td>
<td>August 25, 2015</td>
<td>Added “or” to Requirement R5, 5.3 to read: schedules or Reactive Power.</td>
<td>Errata</td>
</tr>
<tr>
<td>4.1</td>
<td>November 13, 2015</td>
<td>FERC Letter Order approved errata to VAR-001-4.1. Docket RD15-6-000</td>
<td>Errata</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Generator Operation for Maintaining Network Voltage Schedules
2. Number: VAR-002-4.1
3. Purpose: To ensure generators provide reactive support and voltage control, within generating Facility capabilities, in order to protect equipment and maintain reliable operation of the Interconnection.

4. Applicability:
   4.1. Generator Operator
   4.2. Generator Owner

5. Effective Dates
   See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator 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 generator is being operated in start-up,\(^1\) shutdown,\(^2\) or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
   • That the generator 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 a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

---
\(^1\) Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.
\(^2\) Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule\(^3\) (within each generating Facility’s capabilities\(^4\)) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. \([\text{Violation Risk Factor: Medium}] \ [\text{Time Horizon: Real-time Operations}]\)

2.1. When a generator’s AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

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

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

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

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

For Part 2.1, when a generator’s AVR is out of service or the generator 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.

For Part 2.2, the Generator Operator shall 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 shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

\(^3\) The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.

\(^4\) Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, Reactive Power capability may change based on stability considerations.
R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

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

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

M4. The 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.

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

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

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

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

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5 For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.
R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. [Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]

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

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation in accordance with Requirement R6. The Generator Owner shall 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:
       
       As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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

   1.3. Compliance Monitoring and Assessment Processes:
       
       “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

   1.4. Additional Compliance Information:
       
       None.
**Table of Compliance Elements**

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Unless exempted, the Generator Operator did not operate each generator 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.</td>
</tr>
</tbody>
</table>
## Generator Operation for Maintaining Network Voltage Schedules

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
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<tbody>
<tr>
<td></td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>R2</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
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<td></td>
<td>The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any explanation.</td>
</tr>
<tr>
<td>R3</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td></td>
<td></td>
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<td></td>
<td></td>
<td>The Generator Operator did not make the required notification within 30 minutes of the status change.</td>
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<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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</tr>
<tr>
<td>R4</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.</td>
</tr>
<tr>
<td>R5</td>
<td>Real-time Operations</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Generator Owner 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.</td>
</tr>
</tbody>
</table>
|     |                    |      |           |              |          | The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.
### TABLE 1: Generator Owner’s Real-time Operations

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
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</thead>
<tbody>
<tr>
<td>R6</td>
<td>Real-time Operations</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
</tr>
</tbody>
</table>

The Generator Owner did not ensure the tap changes were made according to the Transmission Operator’s specifications. OR The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator’s specifications.
D. Regional Variances
None.

E. Interpretations
None.

F. Associated Documents
None.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tr>
<td>1</td>
<td>5/1/2006</td>
<td>Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and 2.4.3.</td>
<td>July 5, 2006</td>
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<tr>
<td>1a</td>
<td>12/19/2007</td>
<td>Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007</td>
<td>Revised</td>
</tr>
<tr>
<td>1a</td>
<td>1/16/2007</td>
<td>In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.</td>
<td>Errata</td>
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<tr>
<td>1.1a</td>
<td>10/29/2008</td>
<td>BOT adopted errata changes; updated version number to “1.1a”</td>
<td>Errata</td>
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<tr>
<td>1.1b</td>
<td>3/3/2009</td>
<td>Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009</td>
<td>Revised</td>
</tr>
<tr>
<td>2b</td>
<td>4/16/2013</td>
<td>Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>5/5/2014</td>
<td>Revised under Project 2013-04 to address outstanding Order 693 directives.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>5/7/2014</td>
<td>Adopted by NERC Board of Trustees</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>8/1/2014</td>
<td>Approved by FERC in docket RD14-11-000</td>
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<td>4</td>
<td>8/27/2014</td>
<td>Revised under Project 2014-01 to clarify applicability of Requirements to</td>
<td>Revised</td>
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<td>4</td>
<td>11/13/2014</td>
<td>Adopted by NERC Board of Trustees</td>
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<td>4</td>
<td>5/29/2015</td>
<td>FERC Letter Order in Docket No. RD15-3-000 approving VAR-002-4</td>
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<td>4.1</td>
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<tr>
<td>4.1</td>
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<td>Errata</td>
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</tr>
</tbody>
</table>
Guidelines and Technical Basis

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

Rationale for R1:
This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

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

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

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

Rationale for R3:
This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has
**VAR-002-4.1 Application Guidelines**

also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

**Rationale for R4:**

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

**Rationale for Exclusion in R4:**

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

**Rationale for R5:**

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

**Rationale for Exclusion in R5:**

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

**Rationale for R6:**

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

1. Title: Generator Operation for Maintaining Network Voltage Schedules

2. Number: VAR-002-4.1

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

4. Applicability:
   4.1. Generator Operator
   4.2. Generator Owner

5. Effective Dates
   See Implementation Plan.

B. Requirements and Measures

R1. The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (with its automatic voltage regulator (AVR) in service and controlling voltage) or in a different control mode as instructed by the Transmission Operator unless: 1) the generator 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 generator is being operated in start-up,\(^1\) shutdown,\(^2\) or testing mode pursuant to a Real-time communication or a procedure that was previously provided to the Transmission Operator; or
   - That the generator 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 a generator in the automatic voltage control mode or in a different control mode as specified in Requirement R1. If a generator is being started up or shut down with the automatic voltage control off, or is being tested, and no notification of the AVR status is made to the Transmission Operator, the Generator Operator will have evidence that it notified the Transmission Operator of its procedure for placing the unit into automatic voltage control mode as required in Requirement R1. Such evidence may include, but is not limited to, dated evidence of transmittal of the procedure such as an electronic message or a transmittal letter with the procedure included or attached. If a generator is exempted, the Generator Operator shall also have evidence that the generator is exempted from being in automatic voltage control mode (with its AVR in service and controlling voltage).

---
\(^1\) Start-up is deemed to have ended when the generator is ramped up to its minimum continuously sustainable load and the generator is prepared for continuous operation.

\(^2\) Shutdown is deemed to begin when the generator is ramped down to its minimum continuously sustainable load and the generator is prepared to go offline.
R2. Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power schedule\(^3\) (within each generating Facility’s capabilities\(^4\)) provided by the Transmission Operator, or otherwise shall meet the conditions of notification for deviations from the voltage or Reactive Power schedule provided by the Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

2.1. When a generator’s AVR is out of service or the generator does not have an AVR, the Generator Operator shall use an alternative method to control the generator reactive output to meet the voltage or Reactive Power schedule provided by the Transmission Operator.

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

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

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

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

For Part 2.1, when a generator’s AVR is out of service or the generator 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.

For Part 2.2, the Generator Operator shall 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 shall demonstrate the methodology for converting the scheduled voltage specified by the Transmission Operator to the voltage point being monitored by the Generator Operator.

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3 The voltage or Reactive Power schedule is a target value with a tolerance band or a voltage or Reactive Power range communicated by the Transmission Operator to the Generator Operator.
4 Generating Facility capability may be established by test or other means, and may not be sufficient at times to pull the system voltage within the schedule tolerance band. Also, when a generator is operating in manual control, Reactive Power capability may change based on stability considerations.
R3. Each Generator Operator shall notify its associated Transmission Operator of a status change on the AVR, power system stabilizer, or alternative voltage controlling device within 30 minutes of the change. If the status has been restored within 30 minutes of such change, then the Generator Operator is not required to notify the Transmission Operator of the status change. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]

M3. The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any status change identified in Requirement R3. If the status has been restored within the first 30 minutes, no notification is necessary.

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

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

M4. The 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.

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

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

5.1.1. Tap settings.

5.1.2. Available fixed tap ranges.

5.1.3. Impedance data.

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

---

5 For dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition, this requirement applies only to those transformers that have at least one winding at a voltage of 100 kV or above.
R6. After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement. [Violation Risk Factor: Lower] [Time Horizon: Real-time Operations]

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

M6. The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator’s documentation in accordance with Requirement R6. The Generator Owner shall 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:
   
   As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” refers to NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC 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 Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. The Generator Operator shall maintain all other evidence for the current and previous calendar year.

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

   1.3. Compliance Monitoring and Assessment Processes:
   
   “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.

   1.4. Additional Compliance Information:
   
   None.
### Table of Compliance Elements

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>Unless exempted, the Generator Operator did not operate each generator 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.</td>
</tr>
</tbody>
</table>
## Table: Generator Operation for Maintaining Network Voltage Schedules

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
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<tbody>
<tr>
<td>R2</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Generator Operator did not maintain the voltage or Reactive Power schedule as instructed by the Transmission Operator and did not make the necessary notifications required by the Transmission Operator. OR The Generator Operator did not have an operating AVR, and the responsible entity did not use an alternative method for controlling voltage. OR The Generator Operator did not modify voltage when directed, and the responsible entity did not provide any explanation.</td>
</tr>
<tr>
<td>R3</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Generator Operator did not make the required notification within 30 minutes of the status change.</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
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</tr>
<tr>
<td>R4</td>
<td>Real-time Operations</td>
<td>Medium</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>The Generator Operator did not make the required notification within 30 minutes of becoming aware of the capability change.</td>
</tr>
<tr>
<td>R5</td>
<td>Real-time Operations</td>
<td>Lower</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td>The Generator Owner 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.</td>
</tr>
<tr>
<td></td>
<td></td>
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<td></td>
<td></td>
<td>The Generator Owner failed to provide to its associated Transmission Operator and Transmission Planner two or more of the types of data specified in Requirement R5 Parts 5.1.1, 5.1.2, and 5.1.3.</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels</td>
<td>R6</td>
<td>Real-time Operations</td>
<td>Lower VSL</td>
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<td>-----</td>
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<td></td>
<td></td>
<td>N/A</td>
</tr>
</tbody>
</table>

The Generator Owner did not ensure the tap changes were made according to the Transmission Operator’s specifications.

OR

The Generator Owner failed to perform the tap changes, and the Generator Owner did not provide technical justification for why it could not comply with the Transmission Operator specifications.
D. Regional Variances
None.

E. Interpretations
None.

F. Associated Documents
None.

Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5/1/2006</td>
<td>Added “(R2)” to the end of levels on non-compliance 2.1.2, 2.2.2, 2.3.2, and2.4.3.</td>
<td>July 5, 2006</td>
</tr>
<tr>
<td>1a</td>
<td>12/19/2007</td>
<td>Added Appendix 1 – Interpretation of R1 and R2 approved by BOT on August 1, 2007</td>
<td>Revised</td>
</tr>
<tr>
<td>1a</td>
<td>1/16/2007</td>
<td>In Section A.2., Added “a” to end of standard number. Section F: added “1.”; and added date.</td>
<td>Errata</td>
</tr>
<tr>
<td>1.1a</td>
<td>10/29/2008</td>
<td>BOT adopted errata changes; updated version number to “1.1a”</td>
<td>Errata</td>
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<tr>
<td>1.1b</td>
<td>3/3/2009</td>
<td>Added Appendix 2 – Interpretation of VAR-002-1.1a approved by BOT on February 10, 2009</td>
<td>Revised</td>
</tr>
<tr>
<td>2b</td>
<td>4/16/2013</td>
<td>Revised R1 to address an Interpretation Request. Also added previously approved VRFs, Time Horizons and VSLs. Revised R2 to address consistency issue with VAR-001-2, R4. FERC Order issued approving VAR-002-2b.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>5/5/2014</td>
<td>Revised under Project 2013-04 to address outstanding Order 693 directives.</td>
<td>Revised</td>
</tr>
<tr>
<td>3</td>
<td>5/7/2014</td>
<td>Adopted by NERC Board of Trustees</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>8/1/2014</td>
<td>Approved by FERC in docket RD14-11-000</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>8/27/2014</td>
<td>Revised under Project 2014-01 to clarify applicability of Requirements to</td>
<td>Revised</td>
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</table>
## VAR-002-4.1 — Generator Operation for Maintaining Network Voltage Schedules

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<tr>
<td>4</td>
<td>11/13/2014</td>
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<td>4</td>
<td>5/29/2015</td>
<td>FERC Letter Order in Docket No. RD15-3-000 approving VAR-002-4</td>
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<tr>
<td>4.1</td>
<td></td>
<td>Errata</td>
</tr>
<tr>
<td>4.1</td>
<td></td>
<td>Errata</td>
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</tbody>
</table>
**Guidelines and Technical Basis**

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

**Rationale for R1:**
This requirement has been maintained due to the importance of running a unit with its automatic voltage regulator (AVR) in service and in either voltage controlling mode or the mode instructed by the TOP. However, the requirement has been modified to allow for testing, and the measure has been updated to include some of the evidence that can be used for compliance purposes.

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

Conversion Methodology: There are many ways to convert the voltage schedule from one voltage level to another. Some entities may choose to develop voltage regulation curves for their transformers; others may choose to do a straight ratio conversion; others may choose an entirely different methodology. All of these methods have technical challenges, but the studies performed by the TOP, which consider N-1 and credible N-2 contingencies, should compensate for the error introduced by these methodologies, and the TOP possesses the authority to direct the GOP to modify its output if its performance is not satisfactory. During a significant system event, such as a voltage collapse, even a generation unit in automatic voltage control that controls based on the low-side of the generator step-up transformer should see the event on the low-side of the generator step-up transformer and respond accordingly.

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

**Rationale for R3:**
This requirement has been modified to limit the notifications required when an AVR goes out of service and quickly comes back in service. Notifications of this type of status change provide little to no benefit to reliability. Thirty (30) minutes have been built into the requirement to allow a GOP time to resolve an issue before having to notify the TOP of a status change. The requirement has
**VAR-002-4.1 Application Guidelines**

also been amended to remove the sub-requirement to provide an estimate for the expected duration of the status change.

**Rationale for R4:**

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

**Rationale for Exclusion in R4:**

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

**Rationale for R5:**

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

**Rationale for Exclusion in R5:**

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

**Rationale for R6:**

This requirement and corresponding measure have been maintained due to the importance of having accurate tap settings. If the tap setting is not properly set, then the VARs available from that unit can be affected.
**Draft 2018-2020 Reliability Standards Development Plan**

**Action**
Endorse posting the draft 2018-2020 Reliability Standards Development Plan (RSDP) for a 30-day industry comment period.

**Background**
The 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication so that stakeholders may make available appropriate resources to support the identified standards development objectives. Additional activities, such as Requests for Interpretation and development of Regional Variances, may impact the plan, which is a snapshot of activities anticipated for the 2018-2020 period. In order to help the industry understand resource requirements for each project, the RSDP now shows timeframes and anticipated resources for each project under development.

The Standards Committee (SC) commented on the draft 2018-2020 RSDP from May 12-22, 2017 and recommended no substantive changes. NERC staff will respond to comments and present a revised RSDP draft to the SC for endorsement at a future SC meeting. The RSDP will then be presented to the NERC Board of Trustees (Board) for endorsement, and upon Board approval of the RSDP, NERC will file the RSDP with the appropriate regulatory authorities.
Technical Rationale for Reliability Standards

Action

Background
The Reliability Standards template currently includes a Guidelines and Technical Basis (GTB) section to provide standard drafting teams a mechanism to: (i) explain the technical basis for the associated Reliability Standard (and Requirements therein); and (ii) provide technical guidance to help support effective application of the associated Reliability Standard. With the enactment of the Compliance Guidance Policy, it appears helpful to further clarify the principles, development, and use of GTB. To that end, NERC staff and the Standards Committee (SC) leadership have drafted the “Technical Rationale in Reliability Standards” document to clarify the distinction between Implementation Guidance and material related to technical rationale. This document will be presented to the Standards Oversight and Technology Committee during the August 2017 NERC Board of Trustees meetings.

This document was provided to the SC for review and input prior to this meeting. There were some input and questions that were addressed as follows:

1. There was a question on what will happen to GTB in existing standards. The document is intended to apply on a going forward basis, but the document has been updated to reflect the intent to review existing GTB during active standards development and during Periodic Reviews to determine whether modifications should occur.

2. There was a question on whether the section describing the “NERC Review” would require a change to the Standard Processes Manual. The NERC Review is intended to provide supporting review and guidance to drafting teams to ensure that the principles in this document are realized, and it is not a formal part of the standards development process.

3. There was a question on what was meant by the description that NERC would review the Technical Rational documents “before they are finalized.” The phrase is simply intended to recognize that drafting teams may develop associated documents throughout the standards development timeline, so the review would occur before the Technical Rationale document is finalized.

4. There was input that the description of GTB in the first paragraph for effective “application” caused confusion with the footnoted reference to “implementation.” The introductory paragraph of the document has been updated to clarify that section by removing reference to “application.”

Should an entity seek ERO Enterprise endorsement of a particular compliance approach, it should submit Implementation Guidance for ERO Enterprise consideration, consistent with NERC’s Compliance Guidance Policy. In summary, the Compliance Guidance Policy provides stakeholders with the following process:
Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard that are vetted by industry and endorsed by the ERO Enterprise. The examples provided in the Implementation Guidance are not exclusive, as there are likely other methods for implementing a standard. The ERO Enterprise’s endorsement of an example means the ERO Enterprise Compliance Monitoring and Enforcement Program staff will give these examples deference when conducting compliance monitoring activities. Registered entities can rely upon the example and be reasonably assured that compliance requirements will be met with the understanding that compliance determinations depend on facts, circumstances, and system configurations.
Introduction
The current Reliability Standards template includes a Guidelines and Technical Basis (GTB) section to provide standard drafting teams (SDTs) a mechanism to: (i) explain the technical basis for the associated Reliability Standard (and Requirements therein); and (ii) provide technical guidance for the associated Reliability Standard (and Requirements therein).\(^1\) The ERO Enterprise recognizes that these sections help to understand the technology and technical elements in the Reliability Standard. The ERO continues to assess compliance based on the language of the Reliability Standard and the facts and circumstances presented.

With the use of Implementation Guidance under the Compliance Guidance Policy, it is helpful to clarify the distinction between Implementation Guidance and GTB (or Technical Rationale, as explained below).\(^2\) GTB should focus on technical rationale that assists technical understanding of a requirement and/or Reliability Standard. GTB should not include compliance examples or compliance language, as such information, if needed, should be developed as Implementation Guidance under the Compliance Guidance Policy.

Should an entity seek ERO Enterprise endorsement of a particular compliance approach, it should submit Implementation Guidance for ERO Enterprise consideration consistent with NERC’s Compliance Guidance Policy. In summary, the Compliance Guidance Policy provides stakeholders with the following process:

Implementation Guidance provides a means for registered entities to develop examples or approaches to illustrate how registered entities could comply with a standard that are vetted by industry and endorsed by the ERO Enterprise. The examples provided in the Implementation Guidance are not exclusive, as there are likely other methods for implementing a standard. The ERO Enterprise’s endorsement of an example means the ERO Enterprise [Compliance Monitoring and Enforcement Program] CMEP staff will give these examples deference when conducting compliance monitoring activities. Registered entities can rely upon the example and be reasonably assured that compliance requirements will be met with the understanding that compliance determinations depend on facts, circumstances, and system configurations. (footnote omitted)

The use of the term “guideline” in GTB has created confusion for some stakeholders on the use of

\(^1\) Although not explicitly addressed in the Standards Process Manual (SPM), the use of GTB is consistent with the SPM. Section 2.5 of the SPM provides that a Reliability Standard may include “application guidelines,” which are described as “guidelines to support the implementation of the associated Reliability Standard.” Further, Section 3.6 of the SPM provides that a drafting team may “develop[] and refine[] technical documents that aid in the understanding of Reliability Standards.”

\(^2\) NERC’s Compliance Guidance Policy is available at [http://www.nerc.com/pa/comp/Resources/ResourcesDL/Compliance_Guidance_Policy_FINAL_Board_Accepted_Nov_5_2015.pdf](http://www.nerc.com/pa/comp/Resources/ResourcesDL/Compliance_Guidance_Policy_FINAL_Board_Accepted_Nov_5_2015.pdf). As part of that policy, the Compliance and Certification Committee (CCC) as the lead, with support from the Standards Committee (SC), jointly reviewed in 2016 other existing documents to recommend which should transition and be submitted for ERO Enterprise-endorsement for Implementation Guidance.
information in this section for guidance in developing compliance approaches. To clarify the intended use of information in this section, and to address that confusion, the Reliability Standards template will be revised to eliminate the GTB section and allow for the creation of a separate document containing the Technical Rationale. The purpose of this document is to further clarify the principles, development, and use of GTB (historically) and Technical Rationale. GTB that already exists in Reliability Standards will be reviewed under these principles when a new version of a Reliability Standard is being drafted and during any Periodic Review process.

**Development and Use of Technical Rationale Documents**

To help the development of Technical Rationale on a going-forward basis, the following should be followed by standard drafting teams and stakeholders developing Technical Rationale:

1. Be a separate document that is clearly marked as Technical Rationale for Reliability Standard XXX-XXX-X;
2. Provide stakeholders and the ERO Enterprise an understanding of the technology and technical requirements in the Reliability Standard.
3. Avoid compliance approach(es) to implementing a Reliability Standard.

**NERC Review**

To further support the development principles outlined above on a going–forward basis, NERC staff will also review standard drafting teams’ Technical Rationale for Reliability Standards documents before they are finalized. The purpose of the review is to confirm that a developed Technical Rationale for Reliability Standards document:

1. Does not include compliance approaches, which would be more appropriate as Implementation Guidance.
2. Is consistent with the purpose and intent of the associated Reliability Standard.
3. Has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.
Texas-New Mexico Power Company Request for Interpretation of EOP-008-1 Requirement R4

Action
Reject the Request for Interpretation (RFI) of EOP-008-1 submitted by Texas-New Mexico Power Company, on the grounds that the meaning of the Reliability Standard language at issue is plain on its face.

Background
Pursuant to Section 7.0 of the Standard Processes Manual (SPM), NERC staff recommends that the Standards Committee (SC) reject the RFI on the ground that the meaning of the Reliability Standard language at issue is plain on its face.

Section 7.0 of the SPM states, in part,

The entity requesting the Interpretation shall submit a Request for Interpretation form to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. The NERC Reliability Standards and Legal Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

Section 7.0 identifies the grounds upon which the SC is authorized to reject an RFI. One basis for rejecting an RFI is, “[w]here the meaning of a Reliability Standard is plain on its face.”1 Here, Texas-New Mexico Power seeks clarification on whether an entity must establish tertiary functionality during a planned two week or less outage of its primary or backup functionality. Requirement R4 states that “[t]o avoid requiring tertiary functionality, backup functionality is not required during . . . [p]lanned outages of the primary or backup functionality of two weeks or less.” Since a plain reading of Requirement R4 makes clear that the standard does not require a tertiary functionality in situations of operating under backup functionality during a planned outage of less than two weeks, or during unplanned outages of the primary or backup, functionality the RFI should be rejected.

NERC Standards staff and the Project 2015-08 Emergency Operations standards drafting team chair and vice chair agree with the explanation provided above.

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Under Section 7.0, if the SC rejects the RFI, the SC shall provide a written explanation for rejection to the entity submitting the RFI within 10 business days of the decision to reject. If the SC accepts the RFI, NERC standards staff shall (i) form a ballot pool, and (ii) assemble an interpretation drafting team with the relevant expertise to address the interpretation.
**Note: an Interpretation cannot be used to change a standard.**

**Interpretation 2017-xx: Request for an Interpretation of Reliability Standard EOP-008-1, Requirement R4, for Texas-New Mexico Power Co.**

Date submitted: March 3, 2017

**Contact information for person requesting the interpretation:**

Name: Michael Mertz, VP BTS, Chief Information Officer

Organization: PNM Resources, Inc. (affiliate of Texas New Mexico Power Co.)

Telephone: (505) 241-0676

Email: Michael.Mertz@pnmresources.com

**Identify the standard that needs clarification:**

Standard Number (include version number): EOP-008-1

Standard Title: Loss of Control Center Functionality

**Identify specifically what requirement needs clarification:**

**Requirement Number and Text of Requirement:**

R4. Each Balancing Authority and Transmission Operator shall have backup functionality (provided either through a facility or contracted services staffed by applicable certified operators when control has been transferred to the backup functionality location) that includes monitoring, control, logging, and alarming sufficient for maintaining compliance with all Reliability Standards that depend on a Balancing Authority and Transmission Operator’s primary control center functionality respectively. To avoid requiring tertiary functionality, backup functionality is not required during: \([\text{Violation Risk Factor = High}] \[\text{Time Horizon = Operations Planning}\]

- Planned outages of the primary or backup functionality of two weeks or less
- Unplanned outages of the primary or backup functionality

**Clarification needed:**

Texas New Mexico Power Co. respectfully requests interpretation regarding the interrelationship between the two bulleted exceptions in R4. If an entity experiences an unplanned outage of primary or backup functionality, one may assume that the entity will not conduct any planned outage of the remaining functionality while that unplanned outage continues. However, if an entity has a planned two-week-or-less outage of its primary or...
backup functionality, it is unclear whether the possibility of an unplanned outage of the remaining functionality requires the entity to establish tertiary functionality (a “backup to the backup”) notwithstanding R4’s express statement that “[t]o avoid requiring tertiary functionality, backup functionality is not required during . . . [p]lanned outages of the primary or backup functionality of two weeks or less[.]”

**Background:** Existing NERC requirements EOP-008-1 R4 and EOP-008-1 R8 suggest that under certain circumstances when primary functionality is unavailable, a BA or TOP is allowed to operate using only backup functionality and without any required tertiary functionality. As noted above, R4 allows a BA or TOP to operate using backup functionality (without any required tertiary functionality) during an unplanned primary functionality outage and during a planned primary-functionality outage of two weeks or less.

A BA or TOP’s backup functionality may itself experience an unplanned outage at a time when (a) primary functionality is not available due to a planned primary-functionality outage of two weeks or less and (b) tertiary functionality is not required by R4. Therefore, clarification is needed regarding whether tertiary functionality is required under circumstances where operating conditions reflect both of the bulleted exceptions in R4. Apart from any questions of about whether particular outages may constitute violations of any other Reliability Standards, this interpretation is necessary to determine whether a violation of EOP-008-1 R4 is deemed to result from (a) an unplanned outage of backup functionality that occurs during a planned two-weeks-or-less outage of the primary functionality or (b) an unplanned outage of primary functionality that occurs during a planned two-weeks-or-less outage of the backup functionality.

**Identify the material impact associated with this interpretation:**

**Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.**

If the bulleted exceptions in EOP-008-1 R4 are not considered to have an ‘and/or’ between them, it is possible that all BAs and TOPs may be practically required to have tertiary functionality to prevent an unplanned outage from constituting a violation of EOP-008-1 R4.

If this requirement is not clarified, it is possible that if a BA or TOP successfully switches to its backup Control Center and establishes steady-state operation of that backup functionality (at a time when primary functionality is in a planned outage of two weeks or less), and that BA/TOP later experiences a loss of backup functionality (for any duration) during the planned outage of its primary functionality, then the BA or TOP or the associated Regional Entity may incorrectly believe that (a) the BA or TOP failed to have backup functionality as required by R4 or (b) the BA or TOP was required to have tertiary functionality in order to maintain compliance with R4.

Additionally, without clarification, this requirement may be subject to differing interpretations across Regional Entities, resulting in inconsistent or non-uniform enforcement of this requirement. It is reasonable for different Regional Entities could find that EOP-008-1 R4 has, or has not, been violated where there is an unplanned loss of backup functionality during a planned two-weeks-or-less outage of primary functionality. TNMP respectfully submits that clarification of EOP-008-1 R4 is needed to avoid material impact to all BAs, TOPs and Regional Entities.
## Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Owner</th>
<th>Change Tracking</th>
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</thead>
<tbody>
<tr>
<td>1</td>
<td>April 22, 2011</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>May 27, 2014</td>
<td>Standards Information Staff</td>
<td>Updated template and email address for submittal.</td>
</tr>
</tbody>
</table>
Request for Interpretation of PRC-006-2 Requirement R9

**Action**

Reject the Request for Interpretation (RFI) of PRC-006-2 submitted by Utility Services, Inc., pursuant to Section 7.0 of the Standard Processes Manual (SPM), on the grounds that the meaning of the Reliability Standard language at issue is plain on its face and the question has already been addressed in the record.

**Background**

Section 7.0 of the SPM states, in part:

> The entity requesting the Interpretation shall submit a Request for Interpretation form to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. The NERC Reliability Standards and Legal Staffs shall review the request for interpretation to determine whether it meets the requirements for a valid interpretation. Based on this review, the NERC Standards and Legal Staffs shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

Section 7.0 identifies the grounds upon which the SC is authorized to reject an RFI. Reasons for rejecting an RFI include “[w]here a question has already been addressed in the record” and “[w]here the meaning of a Reliability Standard is plain on its face.”1 In this instance, the clarification Utility Services seeks (specifically, which entity is responsible for development of the Corrective Action Plan referenced in PRC-006-2 Requirement R9) is unnecessary as the development record and the plain language of the standard are both clear that Planning Coordinator is responsible.

In its RFI, Utility Services seek clarification on which entity is responsible for the development of the Corrective Action Plan referenced in the requirement language.

Reliability Standard PRC-006-2, Requirement R9 provides as follows:

**R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.

Notably, the defined term “Corrective Action Plan” in Requirement R9 is linked to the requirement language in Requirement R15 that specifies that the Planning Coordinator is the responsible entity. Requirement R15 provides as follows:

---

R15. Each Planning Coordinator . . . shall develop a Corrective Action Plan and a schedule for implementation by the UFLS entities within its area. . . .

The development record is also clear that the Planning Coordinator is responsible for development of the Corrective Action Plan in PRC-006-2. The term “Corrective Action Plan” and new Requirement R15 were added to PRC-006-2 by Project 2008-02 Undervoltage Load Shedding (UVLS) and Underfrequency Load Shedding (UFLS). The development materials and rationale for the revisions specify that the Planning Coordinator is responsible for development of the Corrective Action Plan in the context of PRC-006-2:

Rationale for Requirement R9: “The “Corrective Action Plan” language was added in response to the FERC directive from Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a Planning Coordinator (PC) assessment. The revised language adds clarity by requiring that each UFLS entity follow the UFLS program, including any Corrective Action Plan, developed by the PC.”

Rationale for Requirement R15: “Requirement R15 was added in response to the directive from FERC Order No. 763, which raised concern that the standard failed to specify how soon an entity would need to implement corrections after a deficiency is identified by a PC assessment. Requirement R15 addresses the FERC directive by making explicit that if deficiencies are identified as a result of an assessment, the PC shall develop a Corrective Action Plan and schedule for implementation by the UFLS entities.”

NERC standards staff and the leadership of the PRC-006-2 standard drafting team have also reviewed the RFI and agree with the explanations provided above.

Under Section 7.0, if the SC rejects the RFI, the SC shall provide a written explanation for rejection to the entity submitting the RFI within 10 business days of the decision to reject. If the SC accepts the RFI, NERC standards staff shall (i) form a ballot pool, and (ii) assemble an interpretation drafting team with the relevant expertise to address the interpretation.
**Note:** an Interpretation cannot be used to change a standard.

<table>
<thead>
<tr>
<th>Interpretation 2014-04: Request for an Interpretation of PRC-006-2, Requirement 9, for Utility Services, Inc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date submitted: 9/25/2015</td>
</tr>
<tr>
<td><strong>Contact information for person requesting the interpretation:</strong></td>
</tr>
<tr>
<td>Name: Brian Robinson</td>
</tr>
<tr>
<td>Organization: Utility Services</td>
</tr>
<tr>
<td>Telephone: 802-241-1400</td>
</tr>
<tr>
<td>Email: <a href="mailto:Brian.Robinson@utilitysvcs.com">Brian.Robinson@utilitysvcs.com</a></td>
</tr>
<tr>
<td><strong>Identify the standard that needs clarification:</strong></td>
</tr>
<tr>
<td>Standard Number (include version number): PRC-006-2</td>
</tr>
<tr>
<td>(example: PRC-001-1)</td>
</tr>
<tr>
<td>Standard Title: Automatic Underfrequency Load Shedding</td>
</tr>
<tr>
<td><strong>Identify specifically what requirement needs clarification:</strong></td>
</tr>
<tr>
<td>Requirement Number and Text of Requirement:</td>
</tr>
<tr>
<td>R9. Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for implementation, including any Corrective Action Plan, as determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets. [VRF: High][Time Horizon: Long-term Planning]</td>
</tr>
<tr>
<td><strong>Identify the material impact associated with this interpretation:</strong></td>
</tr>
<tr>
<td>Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard.</td>
</tr>
<tr>
<td>It is unclear in the requirement which entity is responsible for the development of the Corrective Action Plan. Upon review of the directive issued by FERC in order 763 it is clear that the Planning Coordinator is responsible for the development of the implementation schedule including a potential CAP, but the requirement is unclear and open to interpretation. Please confirm that the PC is the entity responsible for developing the “UFLS program design and schedule for implementation, including any Corrective Action Plan.”</td>
</tr>
</tbody>
</table>
The only performance obligation of the UFLS entity is to provide automatic tripping of Load in accordance with the PC developed program and in accordance with the PC developed schedule.

Version History

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</table>
Project to Review/ Revise the Periodic Review Template

Action
Endorse the attached scope document for a project led by the Standards Committee Process Subcommittee (SCPS) to review the Periodic Review Template and recommend modifications to the Standards Committee (SC) for adoption.

Background
At its March 15, 2017 meeting, the SC approved a project for the SCPS to begin a review of the Periodic Review Template for potential revisions to improve, clarify, and reflect lessons learned from the Periodic Review Teams, stakeholders, and the NERC Standards Developers.

Background information related to the above adopted motion was provided in the one-pager under Item 7 of the March 15, 2017 SC agenda package. Additional background information is provided in the attached draft scope document.

In response to the above motion, the SCPS has developed the attached draft scope document for this project. The SC’s approval of the scope document will enable the SCPS to formally begin work on this project and include this project in the SCPS’s work plan.

The SCPS seeks the SC’s endorsement of the attached scope document, which provides further details on the scope of this task, the recommended membership of the task team, and the proposed project schedule.
SCPS Project Scope Document
Review of the Periodic Review Template

Purpose
Periodic review team members, NERC Standards Developers, and some industry representatives have suggested reviewing and modifying the Periodic Review Template to make the periodic review process more efficient and effective. An enhanced template would not only enhance the review team’s contributions but would also enable stakeholders and decision makers to have more concisely presented information.

Project Scope Statement
Each year, NERC conducts periodic reviews of approved Reliability Standards. In accordance with Section 13 of the NERC Standard Processes Manual (SPM), all Reliability Standards shall be reviewed at least once every ten years, and all Reliability Standards approved by the American National Standards Institute as American National Standards shall be reviewed at least once every five years. The periodic review process involves a number of considerations to determine which standards should be reviewed, and if they should potentially be revised using the standards development process. The periodic review process can result in three outcomes: 1. reaffirmation of the standard; 2. revision of the standard; or 3. retirement of the standard.

The Periodic Review Template is the tool used to guide and document the periodic review process. At its March 15, 2017 meeting, the NERC Standards Committee (SC) approved a project for the Standards Committee Process Subcommittee (SCPS) to begin a review of the Periodic Review Template for potential revisions to improve, clarify, and reflect lessons learned from the Periodic Review Teams, stakeholders, and the NERC Standards Developers.

To accomplish this objective, the SCPS will, collaboratively with NERC staff:

- Review the existing Periodic Review Template to make improvements and clarifications.
- Work with the Periodic Review Teams, as well as the NERC Standards Developers, to incorporate lessons learned.
- Recommend to the SC an improved version of the Periodic Review Template to be posted for industry comments.

Resources
A small team comprised of several SCPS members, NERC Standards staff, and NERC Legal staff will be required to complete this project in a timely manner. The project is expected to last approximately three to four months, with an expected start in June 2017, and projected completion in September 2017, pending SC approval of this scope document at the June 2017 SC meeting.

---

1 This template is posted on the Standards Resources section of the NERC website.
# Standards Committee Process Subcommittee Work Plan (SC Endorsed Project Scopes)

<table>
<thead>
<tr>
<th>Task</th>
<th>General Scope of Task</th>
<th>Task Initiated</th>
<th>Target Completion</th>
<th>Status/Remarks</th>
</tr>
</thead>
</table>
| 1. Revisions to NERC Standard Processes Manual (SPM)  
   a. Section 6: Processes for Conducting Field Tests and Collecting and Analyzing Data  
   b. Section 7: Process for Developing an Interpretation  
   c. Section 11.0: Process for Approving Supporting Documents | a. Develop and propose recommendations to the SC for revisions and/or modifications to the SC Charter Section 10 and Section 6 of the Standards Processes Manual (SPM), which will address the coordination and oversight involvements of the NERC technical committees.  
   b. Develop and propose recommendations to the SC for revisions and/or modifications to the Interpretation Process in Section 7 of the SPM which will improve the effectiveness and efficiency of (i) validation of a request for Interpretation (RFI), and (ii) development of an interpretation of an approved Reliability Standard or individual Requirement(s) within an approved Reliability Standard.  
   c. Develop and propose recommendations to the SC for revisions and/or modifications to the Technical Document Approval Process in Section 11 of the SPM. | July 2015 | March 2017 (delayed to end 2017) | Comments received from the first posting of the revised SPM are being reviewed, and responses to be drafted. A verbal report to the SC regarding next steps will be provided at the June 14 SC meeting. |

**Team Lead: Pete Heidrich**  
John Bussman  
Ben Li  
Jennifer Flandermeyer  
Steve Rueckert  
Chris Gowder  
Sean Bodkin  
Guy Zito (consulting)  
Lauren Perotti (NERC Legal)  
Sean Cavote (NERC)
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<thead>
<tr>
<th>Task</th>
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</thead>
<tbody>
<tr>
<td>2. Evaluate Options to Handle Changes to Implementation Plan Prior to Final Ballot</td>
<td>The objective of this project is to explore options on ways forward with handling changes to the implementation plan associated with draft standards under development, with due consideration to the provisions in the existing Standard Processes Manual (SPM).</td>
<td>December 2016</td>
<td>June 2017 (Completed in April 2017)</td>
<td>(Ref. Agenda Item #8 of April 19, 2017 SC Meeting) SC endorsed the SCPS’s proposed approach to convey to all standard drafting teams of the need to seek advice and determination from the Standards Committee on whether changes to implementation plans are “substantive,” which will require the implementation plan or standard(s) to be posted for an additional comment period and ballot prior to conducting final ballot. The above message will be incorporated into the Drafting Team Reference Manual at its next scheduled update under a new project.</td>
</tr>
<tr>
<td>Team Lead: Ben Li</td>
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<tr>
<td>Chris Chowder</td>
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<tr>
<td>Pete Heidrich</td>
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<td>Lauren Perotti</td>
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<td>Steve Rueckert</td>
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## Standards Committee Process Subcommittee Work Plan (Projects On-Hold)

<table>
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<tr>
<th>Task</th>
<th>General Scope of Task</th>
<th>Task Initiated</th>
<th>Target Completion</th>
<th>Status/Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. <strong>Cost of Risk Reduction Analysis (CRRA)</strong>&lt;br&gt;&lt;br&gt;Team Lead: TBD&lt;br&gt;Pete Heidrich&lt;br&gt;Randy Crissman&lt;br&gt;Steven Rueckert&lt;br&gt;Guy Zito (consulting)</td>
<td>To conduct CEAP pilots via:&lt;br&gt;a. Conducting the CEA portion of the CEAP on the second project of the pilot. The Team will develop a report for the SC and the Industry. &lt;br&gt;b. Proposing a list of standards development projects to conduct the CEAP on along with potential criteria for choosing projects for 2014 and beyond and bring these to the SC for endorsement. &lt;br&gt;c. Revise the current CEAP guideline document into a second-generation document to reflect lessons learned during the pilot and to address potential “benefits” of standard projects and bring to the SC for endorsement.&lt;br&gt;&lt;br&gt;<strong>Task was initiated prior to use of scope documents</strong></td>
<td>April 2012</td>
<td>a) March 2014 SC Meeting&lt;br&gt;b) August 2014 SC Meeting&lt;br&gt;c) September 2015 SC Meeting</td>
<td>a) Completed&lt;br&gt;b) Complete (note: proposal submitted to NERC staff in lieu of SC)&lt;br&gt;c) On hold pending Cost Effectiveness Pilot project and results.&lt;br&gt;In progress&lt;br&gt;Scope of the project was revised to reflect a Cost of Risk Reduction Analysis (CRRA) approach. Endorsed at Sept. 23, 2015 Standards Committee meeting.&lt;br&gt;SCPS continue working with Standards Leadership to evaluate this item and determine next steps.&lt;br&gt;A draft document has been presented to H. Gugel for review. The MRC may need to review some of the issues</td>
</tr>
</tbody>
</table>
## Standards Committee Process Subcommittee Work Plan (Projects On-Hold)

<table>
<thead>
<tr>
<th>Task</th>
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</table>

contained within the document. H. Gugel stated that the NERC Board and others may request input from the MRC, and that NERC staff is currently working to determine the mechanism by which this should occur.

**UPDATE:** Michelle D’Antuono has assumed the role of Project Liaison to coordinate efforts between NERC staff and the SCPS.

Project is ‘on hold’ pending the results of the Cost Effectiveness Pilot project and a determination is made on the future role of the SCPS concerning ‘pilot’ results analysis and process development.

Add to “On Hold” section at the end of the Work Plan.
### Standards Committee Process Subcommittee Work Plan (Conceptual Project Stage-No Scope or Endorsement)

<table>
<thead>
<tr>
<th>Proposed Task</th>
<th>General Scope of Task</th>
<th>Presented to SC for Project Initiation</th>
<th>Scope, Development Initiated</th>
<th>SC Approval of Scope *</th>
<th>Status/Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Review/Revise Periodic Review Assessment Template</td>
<td>Review the current version of the periodic review template and revise it as appropriate</td>
<td>March 2017</td>
<td>Initiated in May 2017</td>
<td>On agenda of the June 2017 SC meeting</td>
<td>A subgroup has been formed. Project to formally start upon SC’s approval of the proposed scope.</td>
</tr>
</tbody>
</table>

*Team Lead: Ruida Shu  
Jennifer Flandermeyer  
Laura Anderson

*Upon approval of project Scope, the project will be moved to the “Standards Committee Process Subcommittee Work Plan (SC Endorsed Project Scopes) section.*
**NERC Legal and Regulatory Update**  
March 29, 2017 – May 30, 2017

**NERC Filings to FERC Submitted Since Last SC Update**

<table>
<thead>
<tr>
<th>FERC Docket No.</th>
<th>Filing Description</th>
<th>FERC Submittal Date</th>
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<tbody>
<tr>
<td>RM15-11-000</td>
<td>Informational Filing of NERC Regarding the Geomagnetic Disturbance Research Work Plan</td>
<td>5/30/2017</td>
</tr>
<tr>
<td>RM17-12-000</td>
<td>Errata to Petition of NERC for Approval of Proposed EOP Reliability Standards</td>
<td>4/28/2017</td>
</tr>
<tr>
<td>RM16-20-000</td>
<td>Comments of NERC in Response to PRC-012-2 NOPR</td>
<td>4/10/2017</td>
</tr>
<tr>
<td>RM16-13-000</td>
<td>Response of NERC to Data Request</td>
<td>4/6/2017</td>
</tr>
<tr>
<td>RR09-6-003</td>
<td>2017 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives</td>
<td>3/31/2017</td>
</tr>
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</table>
### FERC ISSUANCES SINCE LAST SC UPDATE
(any standard development related directives or proposed directives are noted in the summary)

<table>
<thead>
<tr>
<th>FERC Docket No.</th>
<th>Issuance Description</th>
<th>FERC Issuance Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>RD17-4-000</td>
<td>Letter Order Approving Reliability Standards IRO-002-5 and TOP-001-4 FERC issues a delegated order approving Reliability Standards IRO-002-5 (<em>Reliability Coordination - Monitoring and Analysis</em>) and TOP-001-4 (<em>Transmission Operations</em>).</td>
<td>4/17/2017</td>
</tr>
</tbody>
</table>

### UPCOMING FILING DATES

<table>
<thead>
<tr>
<th>FERC Docket No.</th>
<th>Filing Description</th>
<th>Projected Filing Date</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NERC will submit a quarterly filing in Nova Scotia of FERC-approved Reliability Standards.</td>
<td>5/31/2017</td>
</tr>
</tbody>
</table>
Information only
NERC asked the Compliance and Certification Committee (CCC) to review and suggest improvements for data retention and sampling in standards during the Reliability Assurance Initiative (RAI) activities. The Chair of the CCC recently provided the CCC an opportunity to review the below-listed material, originally delivered in October 2014, to determine whether the material is still pertinent. Following its review, the CCC believes the material still achieves the goal of the original project to develop a uniform approach for consideration for data retention in standards as new Reliability Standards are developed, or existing ones revised.

Data Retention Materials Prepared by the CCC:
- Presentation on Team Final Report
- Data Retention Team Whitepaper
  - Appendix 1 – Frequently Asked Questions
  - Appendix 2 – References
  - Appendix 3 – NERC Reliability Standards data retention requirements
  - Appendix 4 – GAGAS references
  - Appendix 5 – Rules of Procedure references
  - Appendix 6 – Data Retention Survey Results
  - Appendix 7 – Common data types
At NERC’s request, the Compliance and Certification Committee established a Reliability Assurance Initiative (RAI) task force to look at issues and make recommendations related to compliance data retention and sampling. The team included members of NERC and Regional Entities as well as industry experts beyond the CCC.

The task force completed its work and developed a whitepaper along with appendices (attached). A survey of 159 Registered Entities found that the primary issues of concern in this area are:

- Differing data retention among the standards (one whitepaper appendix outlines the differing requirements).

- The amount of data by ERO Audit Teams.

- ERO Audit Teams asking for data that is no longer relevant to current operations.

The whitepaper has specific recommendations with regard to standards’ compliance elements, RSAWs, and data sampling for audits. The high level recommendations are:

- Improve RSAWs (see stakeholder comments in whitepaper)

- Standardize data retention to 4 years with the exception of
  - Voice and audio recordings: 90-day rolling retention period
  - High-volume data: six-month rolling retention period
  - Standards requiring a current program or procedure, which would restrict to the currently effective version with a revision history specifying changes and dates of review
• Audit sampling should focus on the most recent two years, unless the sample would be statistically too small

• ERO Enterprise issue guidance to both auditors and registered entities explaining how retention periods would apply in an audit setting

• Temporary use of a log to capture “ad hoc” requests during audits as a resource for process improvement (better data requests and auditor training)

• The CCC’s Compliance Processes and Procedures Subcommittee (CPPS) will work with NERC on addressing and implementing the recommendations.

The CPPS would like to start dialog with NERC Standards and Compliance Operations Staff, and members of the Standards Committee to develop a game plan for implementing the recommendations.

Please contact Patti Metro (CCC Chair), Matthew Goldberg (CPPS Chair) or Terry Bilke (Task Force Lead) to set up time for phone call.
• Team members
• Team scope and deliverables
• Team activities
• Recommendations
Team Members

- Ed Kichline  Ed.Kichline@nerc.net
- Leigh Anne Faugust  leigh.faugust@nerc.net
- Terry Bilke  TBilke@misoenergy.org
- Kevin Conway  kevinc@intellibind.com
- Jennifer Flandermeyer  Jennifer.Flandermeyer@kcpl.com
- Ajay Garg  ajay.garg@HydroOne.com
- Lou Oberski  lou.oberski@dom.com
- Rick Terrill  rick.terrill@luminant.com
- Barb Kedrowski  Barbara.Kedrowski@we-energies.com
- Derrick Davis  Derrick.Davis@TEXASRE.org
Team Scope and Deliverables

Objective: Identify/recommend improvements to make data retention and sampling more efficient/effective and less burdensome

☑ Catalog existing data retention requirements (differences in standards, RoP, Compliance Process Bulletin, etc.)

☑ Identify the types/classes of data and information audited (Real time data, documentation, event triggered, etc.)

☑ Outline principles of data retention and sampling
  - What amount of data is necessary to satisfy compliance
  - Amount needed to provide assurance the reliability goals are being met

☑ Identify, via survey and other outreach, problems experienced in data retention and sampling

☑ Draft whitepaper/report with recommendations based on survey and team research
Your Region(s) and Audit Cycle (check all that apply, including if you are subject to two audit cycles)
Data Retention Challenges

Which do you consider the most challenging or problematic issue with regard to data retention for compliance (where 1 is the most problematic and 5 is the least troublesome):

- Differing retention periods among the standards
- Being asked for data that is no longer relevant
- The volume of data requested
- The storage requirements
- Conflicts between the data retention in the standards and my other retention obligations

Graph showing the distribution of responses for each issue.
• Improve RSAWs (see stakeholder comments in whitepaper)
• Standardize data retention to 4 years with the exception of
  ▪ Voice and audio recordings: 90-day rolling retention period
  ▪ High-volume data: six-month rolling retention period
  ▪ Standards requiring a current program or procedure, which would restrict to the currently effective version with a revision history specifying changes and dates of review
• Audit sampling should focus on the most recent two years, unless the sample would be statistically too small
• ERO Enterprise issue guidance to both auditors and registered entities explaining how retention periods would apply in an audit setting
• Temporary use of a log to capture “ad hoc” requests during audits as a resource for process improvement (better data requests and auditor training)
• CPPS assistance NERC with any future support
Questions and Answers
Appendix 1: Frequently Asked Questions

Does this replace the retention periods in existing Standards?

No. These recommendations are intended to apply to new NERC Reliability Standards and to those Standards silent on retention. The Standard drafting teams will revise the retention periods in current Standards during those Standards’ five-year review.

If the proposed retention period is longer than existing Standards, does this mean that auditors can ask for more information than what they do today?

No. The proposed retention period is for only those Standards currently silent on retention period. Retention periods of less than the four-year retention period may still be set, but in the case of high-volume data, recommendations will have a lower six-month rolling retention period.

Does the four-year retention period supersede our business needs and other regulatory obligations that require longer retention?

No. These recommendations apply only to NERC Standards auditing obligations. Registered entities may choose to retain data for a longer retention period if desired. However, unless the data is associated with an event, auditors should refrain from sampling data older than two years, or requesting data outside of the four-year default retention period.
Appendix 2: References


## Appendix 3: NERC Reliability Standards data retention requirements

<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
<th>Enforcement Date</th>
<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAL-001-0.1a</td>
<td>Real Power Balancing Control Performance</td>
<td>5/13/2009</td>
<td>One year</td>
<td>R1-R2 Medium R3-R4 Lower</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>BAL-002-1</td>
<td>Disturbance Control Performance</td>
<td>4/1/2012</td>
<td>One year</td>
<td>R1, R2.1, R3 High R2, R2.6, R4, R6 Medium, R2.2-R2.5, R5 Lower</td>
<td>R1, R1.1, R3-R6 Real Time Rest are Long Term Planning</td>
</tr>
<tr>
<td>BAL-003-0.1b</td>
<td>Frequency Response and Bias</td>
<td>6/29/2009</td>
<td>None identified</td>
<td>R1 Lower R2 Medium (subs are Lower) R3 Medium R4 Lower R5-R6 Medium</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>BAL-004-0</td>
<td>Time Error Correction</td>
<td>6/18/2007</td>
<td>None identified</td>
<td>R1-R2, R4 Lower R3 Medium (subs are Lower)</td>
<td>Same-day operations</td>
</tr>
<tr>
<td>BAL-005-0.2b</td>
<td>Automatic Generation Control</td>
<td>9/13/2012</td>
<td>One year</td>
<td>R1, R3-R8, R11, R12 (subs are R12.1 Lower, R12.2 and.3 Medium) Medium R2, R10, R16, R17 High R9, R13-R15 Lower</td>
<td>R1, R3, R5, R10, R11, R12, R14-R17 Long Term Planning Rest are Real-time Operations</td>
</tr>
<tr>
<td>Standard</td>
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</tr>
<tr>
<td>BAL-006-2</td>
<td>Inadvertent Interchange</td>
<td>4/1/2011</td>
<td>None identified</td>
<td>Lower</td>
<td>R1, R4-5 Operations Assessment</td>
</tr>
<tr>
<td></td>
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<td></td>
<td>R2-R3 Operations Planning</td>
</tr>
<tr>
<td>COM-001-1.1</td>
<td>Telecommunications</td>
<td>5/13/2009</td>
<td>1) Current plus previous two years&lt;br&gt;2) 90 days&lt;br&gt;3) Current documents&lt;br&gt;4) 90 days</td>
<td>R1 High&lt;br&gt;R2 Medium&lt;br&gt;R3 Lower&lt;br&gt;R4 Medium&lt;br&gt;R5-R6 Lower</td>
<td>R1, R3, R5-6 Long Term Planning&lt;br&gt;R2, R4 Same-day Operations</td>
</tr>
<tr>
<td>COM-002-2</td>
<td>Communications and Coordination</td>
<td>6/18/2007</td>
<td>1) Current plus previous two years&lt;br&gt;2) 90 days</td>
<td>R1, R2 High&lt;br&gt;(R2.1 only Medium)</td>
<td>Real-time Operations</td>
</tr>
<tr>
<td>CIP-001-2a +B17:H20</td>
<td>Sabotage Reporting</td>
<td>10/1/2011</td>
<td>1) Current, in-force documents&lt;br&gt;2) If found non-compliant, than until found compliant or for two years (plus current year) - longer of the two&lt;br&gt;3) One year from the date that an investigation is closed&lt;br&gt;4) Last periodic audit report and all requested and submitted subsequent compliance records</td>
<td>Medium</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>CIP-002-3</td>
<td>Cyber Security — Critical Cyber Asset Identification</td>
<td>10/1/2010</td>
<td>1) Documentation from the previous full calendar year (unless otherwise directed by CEA)&lt;br&gt;2) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records</td>
<td>R1, R1.2 Medium&lt;br&gt;(remaining subs are Lower)&lt;br&gt;R2-R3 High&lt;br&gt;(subs Lower)&lt;br&gt;R4 Lower</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>CIP-002-5</td>
<td>Cyber Security — BES Cyber System Categorization</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant&lt;br&gt;2) Until mitigation is complete and approved or for the time specified above, whichever is longer&lt;br&gt;3) Last audit records and all requested and submitted subsequent audit records</td>
<td>R1 High, R2 Lower</td>
<td>Operations Planning</td>
</tr>
<tr>
<td>Standard</td>
<td>Title</td>
<td>Enforcement Date</td>
<td>Data Retention</td>
<td>Violation Risk Factor</td>
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</tbody>
</table>
| CIP-003-3  | Cyber Security — Security Management Controls      | 10/1/2010        | 1) Documentation from the previous full calendar year (unless otherwise directed by CEA)  
2) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records | R1, R2, R4 Medium (subs are Lower)  
R3, R5 Lower  | Long Term Planning                                  |
| CIP-003-5  | Cyber Security — Security Management Controls      | 4/1/2016         | 1) Evidence of each requirement for three calendar years or if found non-compliant  
2) Until mitigation is complete and approved or for the time specified above, whichever is longer  
3) Last audit records and all requested and submitted subsequent audit records | R1, R3 Medium, R2, R4 Lower  | Operations Planning                                  |
| CIP-004-3a | Cyber Security — Personnel & Training              | 12/12/2012       | 1) PRA documents need to be kept in accordance with federal, state, provincial, and local laws  
2) Documentation from the previous full calendar year (unless otherwise directed by CEA)  
3) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records | R1, R2, R2.2.1-R2.2.3, R2.3, R3.1-R4.2 Lower  
The rest are Medium | Long Term Planning                                  |
| CIP-004-5  | Cyber Security — Personnel & Training              | 4/1/2016         | 1) Evidence of each requirement for three calendar years or if found non-compliant  
2) Until mitigation is complete and approved or for the time specified above, whichever is longer  
3) Last audit records and all requested and submitted subsequent audit records | R1, R2, R4 Lower, R3, R5 Medium | Operations Planning for all requirements, Same-day Operations also for R4, R5 |
| CIP-005-3a | Cyber Security — Electronic Security Perimeter(s)   | 2/2/2011         | 1) Logs for a minimum of ninety calendar days unless longer retention is required pursuant to CIP-008-3 R2  
2) Documentation from the previous full calendar year (unless otherwise directed by CEA)  
3) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records | R1-R4 Medium R1.6, R2.5-R2.6, R4.1 Lower | Long Term Planning                                  |
<table>
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<tr>
<th>Standard</th>
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</thead>
<tbody>
<tr>
<td>CIP-005-5</td>
<td>Cyber Security — Electronic Security Perimeter(s)</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>Medium</td>
<td>Operations Planning and Same-day Operations</td>
</tr>
<tr>
<td>CIP-006-3c</td>
<td>Cyber Security — Physical Security of Critical Cyber Assets</td>
<td>5/19/2011</td>
<td>1) Documentation from the previous full calendar year (unless otherwise directed by CEA) not including those for R7 and R8.2 2) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records 3) Access logs need to be kept for 90 days 4) Retention of testing and maintenance on a cycle no longer than three years, retention of outage records minimum of one year</td>
<td>R1-R5, R8 Medium R1.7, R1.8, R6, R7, R8.2-8.3 Lower</td>
<td>R6 Real-time Operation, the rest are Long Term Planning</td>
</tr>
<tr>
<td>CIP-006-5</td>
<td>Cyber Security — Physical Security of BES Cyber Systems</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>R1, R2 Medium, R3 Lower</td>
<td>R1 Long Term Planning and Same-day Operations, R2 Same-day Operations, R3 Long Term Planning</td>
</tr>
<tr>
<td>CIP-007-3a</td>
<td>Cyber Security — Systems Security Management</td>
<td>10/1/2010</td>
<td>1) Documentation from the previous full calendar year (unless otherwise directed by CEA) 2) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records 3) Security-related system event logs for 90 days</td>
<td>R1, R2, R4, R5.1, R5.1.3, R5.2.1, R6.1-R6.3, R8.2-8.3 Medium R1 Subs, R3, R5 (the rest of), R6, R6.4, R7, R8, R9 Lower</td>
<td>R1, R1.1, R3, R4.1, R5.1-R6.1, R7, R9 Long Term Planning R7.1-7.2 Same Day R4, R4.2, R6.2 Real-time Operations R1.2-R2.3, R3.2, R6.3-R6.5, R7.3, R8 Operations Assessment R3.1, R5.1.1-R5.1.2 Operations Planning</td>
</tr>
<tr>
<td>Standard</td>
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<tr>
<td>CIP-007-5</td>
<td>Cyber Security — System Security Management</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>Medium</td>
<td>R1, R3 Same-day Operations, R2, R5 Operations Planning, R4 Same-day Operations and Operations Assessment</td>
</tr>
<tr>
<td>CIP-008-3</td>
<td>Cyber Security — Incident Reporting and Response Planning</td>
<td>10/1/2010</td>
<td>Three years</td>
<td>Lower</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>CIP-008-5</td>
<td>Cyber Security — Incident Reporting and Response Planning</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>Lower</td>
<td>R1, Long Term Planning, R2 Operations Planning and Real-time Operations, R3 Operations Assessment</td>
</tr>
<tr>
<td>CIP-009-3</td>
<td>Cyber Security — Recovery Plans for Critical Cyber Assets</td>
<td>10/1/2010</td>
<td>1) Documentation from the previous full calendar year (unless otherwise directed by CEA) 2) CEA or entity needs to keep the last audit records and all requested and submitted subsequent audit records</td>
<td>R1 Medium R2-R5 Lower</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>CIP-009-5</td>
<td>Cyber Security — Recovery Plans for BES Cyber Systems</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>R1 Medium, R2, R3 Lower</td>
<td>R1 Long Term Planning, R2 Operations Planning and Real-time Operations, R3 Operations Assessment</td>
</tr>
<tr>
<td>CIP-010-1</td>
<td>Cyber Security — Configuration Change Management and Vulnerability Assessment</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>Medium</td>
<td>Operations Planning and Long Term Planning</td>
</tr>
<tr>
<td>Standard</td>
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<tr>
<td>CIP-011-1</td>
<td>Cyber Security – Information Protection</td>
<td>4/1/2016</td>
<td>1) Evidence of each requirement for three calendar years or if found non-compliant 2) Until mitigation is complete and approved or for the time specified above, whichever is longer 3) Last audit records and all requested and submitted subsequent audit records</td>
<td>R1 – Medium R2 – Lower</td>
<td>Operations Planning</td>
</tr>
</tbody>
</table>

**Emergency Preparedness and Operations (EOP)**

<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
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<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
</tr>
</thead>
<tbody>
<tr>
<td>EOP-002-3.1</td>
<td>Capacity and Energy Emergencies</td>
<td>9/13/2012</td>
<td>1) Measure 1 - current in-force documents 2) Measures 2, 8, 9 - 90 days of historical data (RC) 3) Measure 3, 4, 5, 6, 7 - 90 days of historical data (BA) 4) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer. 5) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA. 6) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records</td>
<td>R9.3-9.4 Lower Remainder are High</td>
<td>R1 is Real-time Operation and Long Term Planning, the remainder are Real-time Operation</td>
</tr>
<tr>
<td>Standard</td>
<td>Title</td>
<td>Enforcement Date</td>
<td>Data Retention</td>
<td>Violation Risk Factor</td>
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</tbody>
</table>
| EOP-003-1 | Load Shedding Plans    | 6/18/2007        | 1) Current in-force documents  
2) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA.  
4) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records | High                   | R1, R5-R7 Real-time Operation R2-R4, R8 Long Term Planning |
| EOP-003-2 | Load Shedding Plans    | 10/1/2013        | 1) Current in-force documents  
2) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA.  
4) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records | High                   | None identified           |
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<tr>
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</thead>
</table>
| EOP-004-1  | Disturbance Reporting| 6/18/2007        | 1) Measure 1 - current in-force documents  
2) Measures 2-4 - one year from the incident or duration of investigation (longer)  
3) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
4) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA.  
5) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records | R2 Medium Remainder Lower | R1 Long Term Planning Remainder Operations Assessment                                                                                                                                                                                                                     |
| EOP-004-2  | Event Reporting      | 1/1/2014         | 1) Each Responsible Entity shall retain the current Operating Plan plus each version issued since the last audit for requirements R1, and Measure M1.  
2) Each Responsible Entity shall retain evidence of compliance since the last auditor requirements R2, R3 and Measure M2, M3.  
3) 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.  
4) The CEA shall keep the last audit records and all requested and submitted subsequent audit records. | R1 Lower, R2-R3 Medium | R1 Long Term Planning Remainder Operations Assessment                                                                                                                                                                                                                     |
<table>
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<tr>
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</table>
| EOP-005-2  | System Restoration Plans                             | 7/1/2013         | 1) Current and enforce restoration plans since last audit  
2) All versions for the current calendar year and the prior three years for approved and reviewed restoration plans - M2, M3, M4, M5  
3) Verification results for current plan for M6  
4) Three years of resynchronization with disturbance  
5) Verification process and results for current and last previous blackstart resource testing requirements  
6) Training program materials for three years  
7) Records of participation since last audit plus previous compliance audit period for M12  
8) M11 - three years  
9) M13 - since last audit  
10) M14 - in force documents since last audit  
11) Notifications to TOPs for last three years M15  
12) Verification results for current and one previous M16  
13) Training materials and records for three years M17  
14) Records for drills and exercises since last audit M18  
15) For any requirement found non-compliant records must be kept until compliant | R1, R7-R8 High  
R5 Lower  
R2-R4, R6, R9 Medium | Long Term Planning  
R9 Real-time Operations |
| EOP-006-2  | Reliability Coordination – System Restoration         | 7/1/2013         | 1) Current and in-force restoration plans since last audit  
2) Distribution of current plan for current year and prior three years M2  
3) Reviewed restoration plans for current review and three prior review periods M3  
4) Copies of neighbor RC plans for current year + 3 M4  
5) Reviewed plans for current +3 M5 and M6  
6) Implementation of restoration plan from event or resynchronization of an islanded area on rolling 12 month period M7 and M8  
7) Training materials and records for three years M9  
8) Records for drills and exercises | R1, R7-R8 High  
R2, R6 Lower  
R3-R5, R9, R10 Medium | R1, R3, R7-R9, R10 Long Term Planning  
Remainder Real-time Operation |
<table>
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<tr>
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</thead>
</table>
| EOP-008-1  | Plans for Loss of Control Center Functionality   | 7/1/2013          | 1) Dated evidence since the last audit  
2) Operating plan copies for the current year (current in-force)  
3) Testing data for current year +1 previous  | R1, R5-R8 Medium  
R2 Lower  
R3-R4 High                               | Long Term Planning                                       |
| FAC-001-0  | Facility Connection requirements                 | 6/18/2007         | None identified                                                                | Medium                     | Long Term Planning     |
| FAC-001-1  | Facility Connection requirements                 | 11/25/2013        | Retain evidence since last audit period.                                        | Medium                     | None identified        |
| FAC-002-1  | Coordination of Plans For New Generation, Transmission, and End-User Facilities | 10/1/2011         | Three years                                                                    | R1 Medium  
R2 Lower                                   | Long Term Planning                                       |
| FAC-003-1  | Transmission Vegetation Management Program       | 6/18/2007         | Five years                                                                     | R1, R2 High  
R3, R4 Lower                                 | Long Term Planning                                       |
| FAC-003-3  | Transmission Vegetation Management Program       | 7/1/2014          | 1) M1, M2, M3, M5, M6, M7, - data retention for 3 calendar years  
2) 12 months of operator logs and 3 months of voice recordings  
Evidence may be retained longer as a part of a compliance investigation.  
3) CEA may ask entity to provide evidence of compliance for the entire audit period  | R1, R2 High  
R3 Lower  
R4-R7 Medium                                | R1, R2, R4 Real-time Operations,  
R3 Long Term Planning, R5, R6, R7 Operations Planning |
<table>
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<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>FAC-008-3</td>
<td>Facility Ratings</td>
<td>1/1/2013</td>
<td>1) Facility ratings methodology documents - current plus any modifications during the compliance audit period 2) Facility ratings - current plus three calendar years Note: the data retention requirements do not align with the Measures</td>
<td>R1, R4, R5 Lower R2, R3, R6, R7 Medium</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>FAC-010-2.1</td>
<td>System Operating Limits Methodology for the Planning Horizon</td>
<td>4/19/2010</td>
<td>Current SOL Methodology documents, plus the Planning Authority shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology</td>
<td>R1, R3 Lower, R4, R5 Lower R2, R3.4, R3.6 Medium</td>
<td>R5 Operations Planning, the rest are Long Term Planning</td>
</tr>
<tr>
<td>FAC-011-2</td>
<td>System Operating Limits Methodology for the Operations Horizon</td>
<td>4/29/2009</td>
<td>Current SOL Methodology documents, plus the Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology</td>
<td>R1, R4, R5 Lower R2 High R3 Medium</td>
<td>R5 Operations Planning, the rest are Long Term Planning</td>
</tr>
<tr>
<td>FAC-013-2</td>
<td>Assessment of Transfer Capability for the Near-Term Transmission Planning Horizon</td>
<td>4/1/2013</td>
<td>1) Current and prior versions since last audit 2) All since last audit M3, M4, M5, 3) Evidence for most recent annual assessment</td>
<td>R1, R4 Medium R2, R3, R5, R6 Lower</td>
<td>R1 Long Term Planning Remainder Operations Planning</td>
</tr>
<tr>
<td>FAC-014-2</td>
<td>Establish and Communicate System Operating Limits</td>
<td>4/29/2009</td>
<td>12 months</td>
<td>R1-R4, R5.1.1-R6.2 Medium R5, R5.1 High</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td><strong>Interchange Scheduling and Coordination (INT)</strong></td>
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<tr>
<td>INT-001-3</td>
<td>Interchange Information</td>
<td>8/27/2008</td>
<td>1) 90 days of historical data (evidence). 2) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer. Evidence used as part of an investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA. 3) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records.</td>
<td>Lower</td>
<td>Same-day operations</td>
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<td>Standard</td>
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<tr>
<td>INT-003-3</td>
<td>Interchange Transaction Implementation</td>
<td>4/1/2011</td>
<td>1) 90 days of historical data (evidence). 2) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer. Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA. 3) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records.</td>
<td>R1, R1.2 Medium (remaining subs are Lower)</td>
<td>Real-time Operations</td>
</tr>
<tr>
<td>INT-004-2</td>
<td>Dynamic Interchange Transaction Modifications</td>
<td>8/27/2008</td>
<td>3 months</td>
<td>Lower</td>
<td>Same-day operations</td>
</tr>
<tr>
<td>INT-005-3</td>
<td>Interchange Authority Distributes Arranged Interchange</td>
<td>7/1/2010</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Medium</td>
<td>Real-time Operation</td>
</tr>
<tr>
<td>INT-006-3</td>
<td>Response to Interchange Authority</td>
<td>7/1/2010</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Lower</td>
<td>Same-day operations</td>
</tr>
<tr>
<td>INT-007-1</td>
<td>Interchange Confirmation</td>
<td>6/18/2007</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Lower</td>
<td>Same-day operations</td>
</tr>
<tr>
<td>INT-008-3</td>
<td>Interchange Authority Distributes Status</td>
<td>7/1/2010</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Lower</td>
<td>Same-day operations</td>
</tr>
<tr>
<td>INT-009-1</td>
<td>Implementation of Interchange</td>
<td>6/18/2007</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Medium</td>
<td>Real-time Operations</td>
</tr>
<tr>
<td>INT-010-1</td>
<td>Interchange Coordination Exemptions</td>
<td>6/18/2007</td>
<td>1) 90 days of historical data 2) The CEA shall keep audit records for a minimum of three calendar years.</td>
<td>Lower</td>
<td>Real-time Operations</td>
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</table>
| IRO-001-1.1 | Reliability Coordination — Responsibilities and Authorities         | 5/13/2009        | 1) Current in-force documents  
2) If found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation for one year after investigation closed  
4) CEA shall keep last periodic audit report and all requested and submitted subsequent compliance records | R1-R3 High  
R4 Medium  
R5 Lower  
R6 Medium  
R7-R9 High | R1, R2, R4, R5, R6, R7 - Long Term Planning  
R3 Real time Operations  
Long Term Planning  
R8, R9 Real-time Operations |
| IRO-001-3 | Reliability Coordination — Responsibilities and Authorities         | Pending          | 1) Voice recordings for most recent 90 days or documentation for most recent 12 months  
2) If found non-compliant then until mitigation is complete and approved or for time specified above (longer)  
3) CEA keeps last audit records and requested and submitted subsequent audit records | High | Operations Planning  
Real-time Operations  
Same-day Operations |
| IRO-002-2 | Reliability Coordination — Facilities                               | 10/1/2011        | 1) Current in-force documents  
2) If found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA  
4) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records. | Medium/High | Long Term Planning |
| IRO-002-3 | Reliability Coordination – Analysis Tools                            | Pending          | 1) Current in-force documents and any documents in force for the current year and the previous calendar year  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted subsequent audit records | Medium | Operations Planning  
Real-time Operations  
Same-day Operations |
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<th>Violation Time Horizon</th>
</tr>
</thead>
</table>
| IRO-003-2 | Reliability Coordination — Wide-Area View                           | 6/18/2007        | 1) Current in-force documents  
2) If found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA  
4) The CEA shall keep the last periodic audit report and all requested and submitted subsequent compliance records. | High                  | Real-time Operations               |
| IRO-005-3.1a | Reliability Coordination — Current Day Operations                     | 9/13/2012        | 1) Current in-force documents  
2) If found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
3) Evidence used as part of a triggered investigation for one year after investigation closed  
4) CEA shall keep last periodic audit report and all requested and submitted subsequent records  
5) 90 days of historical data | High (Pending)            | Real-time Operations               |
| IRO-005-4 | Reliability Coordination — Current Day Operations                     | Pending          | 1) Voice recordings for most recent 90 days or documentation for most recent 12 months  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted subsequent audit records | Medium - High      | Operations Planning, Real-time Operations, Same-day Operations |
| IRO-006-5 | Reliability Coordination — Transmission Loading Relief (TLR)          | 7/1/2011         | 1) Most recent 12 months plus the current month  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted subsequent audit records | High                  | Real-time Operations               |
| Standard   | Title                                                                 | Enforcement Date | Data Retention                                                                 |
|------------|----------------------------------------------------------------------|------------------|--------------------------------------------------------------------------------|--------------------------------------------------------------------------------|
| IRO-006-   | Transmission Loading Relief Procedure for the Eastern Interconnection | 7/1/2011         | 1) Most recent 12 months plus the current month  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted subsequent audit records |
| EAST-1     |                                                                     |                  | Violation Risk Factor: High-Medium  
Violation Time Horizon: Real-time Operations |
| IRO-006-TRE- | IROL and SOL Mitigation in the ERCOT Region                          | 7/1/2012         | 1) Since it became subject to the requirements or since its last audit, whichever is shorter  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted subsequent audit records |
| 1          |                                                                     |                  | Violation Risk Factor: High-Medium  
Violation Time Horizon: Real-time Operations |
| IRO-006-WECC- | Qualified Transfer Path Unscheduled Flow (USF) Relief                | 7/1/2011         | 1) Three years plus the current, or since the last audit, whichever is longer |
| 1          |                                                                     |                  | Violation Risk Factor: High-Medium  
Violation Time Horizon: Real-time Operations |
| IRO-006-WECC- | Qualified Transfer Path Unscheduled Flow (USF) Relief                | Pending          | 1) Three years plus the current, or since the last audit, whichever is longer  
2) If found non-compliant then until found compliant  
3) CEA keeps last audit records and requested and submitted records |
| 2          |                                                                     |                  | Violation Risk Factor: Medium  
Violation Time Horizon: Operations Planning, Real-time Operations, Same-day Operations |
| IRO-008-1  | Reliability Coordinator Operational Analyses and Real-time Assessments | 10/1/2011        | 1) Rolling 30 dates for R2, rolling three months for R3  
2) CEA keeps last audit records and requested and submitted records |
|            |                                                                     |                  | Violation Risk Factor: High-Medium  
Violation Time Horizon: Real-time Operations |
| IRO-009-1  | Reliability Coordinator Actions to Operate Within IROLs              | 10/1/2011        | 1) Rolling 12 months  
2) CEA keeps last audit records and requested and submitted subsequent audit records and all IROL violation reports submitted since last audit |
|            |                                                                     |                  | Violation Risk Factor: High-Medium  
Violation Time Horizon: Real-time Operations |
| IRO-010-1a | Reliability Coordinator Data Specification and Collection           | 10/1/2011        | 1) Current in force data specification  
2) Most recent distribution  
3) R2 data rolling 90 calendar days  
4) CEA keeps last audit records and requested and submitted records |
|            |                                                                     |                  | Violation Risk Factor: Medium  
Violation Time Horizon: Real-time Operations |
| IRO-014-1  | Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators | 6/18/2007       | 1) Prior calendar year and the current calendar year. The CEA shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance, whichever is longer. |
|            |                                                                     |                  | Violation Risk Factor: Medium-Lower  
Violation Time Horizon: Long Term Planning |

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<tr>
<th>Standard</th>
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<th>Violation Risk Factor</th>
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</tr>
</thead>
<tbody>
<tr>
<td>IRO-014-2</td>
<td>Coordination Among Reliability Coordinators</td>
<td>Pending</td>
<td>1) Current in force document and any in force since last audit for R1 and R2</td>
<td>Lower - Medium - High</td>
<td>Operations Planning, Real-time Operations, Same-day Operations</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>2) Rolling 12 months for R3-R5</td>
<td></td>
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<td>3) Three calendar years plus current calendar year for R6-R8</td>
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<td>4) If found non-compliant then until found compliant</td>
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<td>4) CEA keeps last audit records and requested and submitted records</td>
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<tr>
<td>IRO-015-1</td>
<td>Notifications and Information Exchange Between Reliability Coordinators</td>
<td>6/18/2007</td>
<td>1) Rolling 12 months. 2) The CEA shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance</td>
<td>Medium-Lower</td>
<td>Real-time Operations</td>
</tr>
<tr>
<td>IRO-016-1</td>
<td>Coordination of Real-time Activities Between Reliability Coordinators</td>
<td>6/18/2007</td>
<td>1) Rolling 12 months. 2) The CEA shall keep compliance data for a minimum of three years or until the Reliability Coordinator has achieved full compliance</td>
<td>Medium-Lower</td>
<td>Real-time Operations</td>
</tr>
<tr>
<td>MOD-001-1a</td>
<td>Available Transmission System Capability</td>
<td>4/1/2011</td>
<td>1) Keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period. 2) TOP shall maintain its current selected method(s) for calculating ATC or AFC and any methods in force since last compliance audit period 3) TSP shall maintain evidence to R2, R4, R6, R7, and R8 for the most recent calendar year plus the current year 4) TSP shall maintain its current, in force ATCID and any prior versions of the ATCID that were in force since the last compliance audit 5) TSP shall maintain evidence to show compliance with R5 for the most recent three calendar years plus the current year. 6) TOP shall maintain evidence to R6 for the most recent calendar year plus the current year. 7) If found noncompliant, it shall keep information related to the non-compliance until found compliant. 8) The CEA shall keep the last audit records and all requested and submitted subsequent audit records.</td>
<td>R1, R2, R3, R6, R7, R8, R9 Medium, R4, R5 Lower</td>
<td>Long Term Planning</td>
</tr>
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<tr>
<td>MOD-004-1</td>
<td>Capacity Benefit Margin</td>
<td>4/1/2011</td>
<td>1) TSP that maintains CBM shall maintain its current, in force CBMID and any prior versions of the CBMID that were in force during the past three calendar years plus the current year to show compliance with R1. 2) TSP, LSE, RP, TP, BA, and TSP shall maintain evidence to show compliance with pertinent requirements for the most recent three calendar years plus the current year. 3) If found non-compliant, it shall keep information related to the non-compliance until found compliant.</td>
<td>R1-R8, R11, R12 Medium, R9, R10 Lower</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>MOD-008-1</td>
<td>Transmission Reliability Margin Calculation Methodology</td>
<td>4/1/2011</td>
<td>1) TOP shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period as part of an investigation 2) TOP shall have its current, in-force TRMID and any TRMIDs in force since last compliance audit period for R1. 3) Retain evidence to show compliance with R2, R3, R4, and R5 for the most recent three calendar years plus the current year. 4) If found non-compliant, it shall keep information related to the non-compliance until found compliant.</td>
<td>Lower</td>
<td>Operations Planning</td>
</tr>
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<tr>
<td>MOD-016-1.1</td>
<td>Documentation of Data Reporting requirements for Actual and Forecast Demands, Net Energy for Load, and Controllable Demand-Side Management</td>
<td>5/13/2009</td>
<td>1) For the Regional Reliability Organization and Planning Authority: Current version of the documentation. 2) For the CEA: Three years of audit information.</td>
<td>Lower</td>
<td>Long Term Planning and Operations Planning</td>
</tr>
<tr>
<td>MOD-017-0.1</td>
<td>Aggregated Actual and Forecast Demands and Net Energy for Load</td>
<td>5/13/2009</td>
<td>None identified.</td>
<td>Medium</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>MOD-018-0</td>
<td>Treatment of Nonmember Demand Data and How Uncertainties are Addressed in the Forecasts of Demand and Net Energy for Load</td>
<td>6/18/2007</td>
<td>None identified.</td>
<td>Medium - Lower</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>MOD-019-0.1</td>
<td>Reporting of Interruptible Demands and Direct Control Load Management</td>
<td>5/13/2009</td>
<td>None identified.</td>
<td>Medium</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>MOD-020-0</td>
<td>Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators</td>
<td>6/18/2007</td>
<td>None identified.</td>
<td>Lower</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>MOD-021-1</td>
<td>Documentation of the Accounting Methodology for the Effects of Demand-Side Management in Demand and Energy Forecasts</td>
<td>4/1/2011</td>
<td>None identified</td>
<td>Lower</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>MOD-025-2</td>
<td>Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability</td>
<td>7/1/2016</td>
<td>Current information or equivalent information and submittal evidence for requirements R1, R2, and R3 for the period since the last compliance audit.</td>
<td>Medium</td>
<td>Long Term Planning</td>
</tr>
<tr>
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<tr>
<td>MOD-026-1</td>
<td>Verification of Models and Data for Turbine/Governor and Load Control System or Plant Volt/VAR Control Functions</td>
<td>7/1/2014</td>
<td>R1, R3, R4, R5, and R6 for three calendar years. R2 evidence shall be the latest model verification data.</td>
<td>R1, R3, R4, R5 Medium, R2, R6 Lower</td>
<td>R1, R3, R4, R5, R6 Operations Planning, R2 Long Term Planning</td>
</tr>
<tr>
<td>MOD-027-1</td>
<td>Verification of Models and Data for Generation Excitation Control or Active Power/Frequency Control Functions</td>
<td>7/1/2014</td>
<td>R1, R3, R4, and R5 for three calendar years. R2 evidence shall be the latest model verification data.</td>
<td>R1, R3, R4 Lower, R2, R6 Medium</td>
<td>R1, R3, R4 Operations Planning, R2 Long Term Planning</td>
</tr>
<tr>
<td>MOD-028-1</td>
<td>Area Interchange Methodology</td>
<td>4/1/2011</td>
<td>1) Current in-force ATCID and prior versions in force since last audit, latest model showing TTC and previous version 2) 12 months for R3, R4, R5, R6, and R7, R10, R11 3) R8 and R9 hourly rolling 14 days, calculating daily for 30 days and monthly for 60 days 4) If found non-compliant than until found compliant 5) CEA keeps last audit records and all requested and submitted subsequent audit records</td>
<td>Lower</td>
<td>Operations Planning</td>
</tr>
<tr>
<td>MOD-028-2</td>
<td>Area Interchange Methodology</td>
<td>Pending</td>
<td>1) Current in-force ATCID and prior versions in force since last audit, latest model showing TTC and previous version 2) 12 months for R3, R4, R5, R6, and R7, R10, R11 3) R8 and R9 hourly rolling 14 days, calculating daily for 30 days and monthly for 60 days 4) If found non-compliant than until found compliant 5) CEA keeps last audit records and all requested and submitted subsequent audit records</td>
<td>Lower</td>
<td>Operations Planning</td>
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</tbody>
</table>
| MOD-029-1a   | Rated System Path Methodology | 4/1/2011         | 1) Latest models, ATCID for R1  
2) evidence of path ratings prior to 1/1/94  
3) latest version and prior version of TTC study reports  
4) Most recent three years plus current year for R3, R4, R7, R8  
5) hourly rolling 14 days, calculating daily for 30 days and monthly for 60 days  
6) If found non-compliant than until found compliant  
7) CEA keeps last audit records and all requested and submitted subsequent audit records | Lower                  | Operations Planning            |
| MOD-030-2    | Flowgate Methodology    | 4/1/2011         | 1) ATCID in force and which has been in force since last audit for R1  
2) latest model and evidence of previous versions  
3) 12 months for R2.1, R2.3  
4) Most recent three years plus current year for R2.2, R2.4, R2.5  
5) hourly rolling 14 days, calculating daily 30 days and monthly 60 days  
6) 12 months for R4  
7) Most recent calendar year plus current year for R5, R8, R9, R10, and R11  
8) If found non-compliant than until found compliant  
9) CEA keeps last audit records and all requested and submitted subsequent audit records | Medium                 | Operations Planning            |
| Nuclear (NUC)|                         |                  |                                                                                  |                       |                        |
| NUC-001-2    | Nuclear Plant Interface Coordination | 4/1/2010         | Various time frames from current to 3 plus years                                | Lower - Medium - High | Operations Planning |
| Personnel Performance, Training, and Qualifications (PER ) |                  |                  |                                                                                  |                       |                        |
| PER-001-0.2  | Operating Personnel Responsibility and Authority | 9/13/2012        | Permanent                                                                      | High                   | Real-time Operations |

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</thead>
</table>
| PER-003-1     | Operating Personnel Credentials           | 10/1/2012         | 1) Three years or since last audit (greater) unless directed otherwise  
2) If found non-compliant than until found compliant  
3) CEA keeps last audit records and all requested and submitted subsequent records | High                  | Long Term Planning                                                  |
| PER-004-2     | Reliability Coordination — Staffing        | 4/1/2011          | 1) Previous two years plus current year  
2) If found non-compliant than until found compliant  
3) If part of an investigation than for one year after the investigation is closed  
4) CEA keeps last periodic audit report and all requested and submitted subsequent compliance records | High                  | Long Term Planning                                                  |
| PER-005-1     | System Personnel Training                 | 4/1/2011          | 1) Previous three years  
2) If found non-compliant than until found compliant  
3) CEA keeps last periodic audit report and all requested and submitted subsequent compliance records | Medium - High        | Long Term Planning                                                  |

**Protection and Control (PRC)**

<table>
<thead>
<tr>
<th>PRC-001-1.1</th>
<th>System Protection Coordination</th>
<th>6/18/2007</th>
<th>1) Current in force document M2, 3) 90 days</th>
<th>High</th>
<th>Real-time Operations</th>
</tr>
</thead>
<tbody>
<tr>
<td>PRC-004-2.1a</td>
<td>Analysis and Mitigation of Transmission and Generation Protection System Misoperations</td>
<td>4/1/2012</td>
<td>12 months or until the corrective action plan has been completed.</td>
<td>Lower - High</td>
<td>Operations Assessment</td>
</tr>
<tr>
<td>PRC-005-1.1b</td>
<td>Transmission and Generation Protection System Maintenance and Testing</td>
<td>3/14/2012</td>
<td>Three years</td>
<td>Lower -High</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>PRC-005-2</td>
<td>Protection System Maintenance</td>
<td>4/1/2015</td>
<td>R1 retain current document plus evidence since last audit. R2-R5 retain two most recent activity documents or all evidence since last audit, whichever is longer.</td>
<td>R1, R2, R5 Medium, R3, R4 High</td>
<td>Operations Planning</td>
</tr>
<tr>
<td>Standard</td>
<td>Title</td>
<td>Enforcement Date</td>
<td>Data Retention</td>
<td>Violation Risk Factor</td>
<td>Violation Time Horizon</td>
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</tr>
</tbody>
</table>
| PRC-006-1  | Automatic Underfrequency Load Shedding                                | 10/1/2013        | 1) M1, M2, M3, M4, M5, M7, M8, M9, M10, M12, M14 - Evidence retained since last audit  
                          2) M6 – Evidence for current year plus prior year  
                          3) M11, M13 – Evidence retained for six years (5-year assessments)  
                          4) Longer for an investigation | Lower – Medium – High                            | Long Term Planning and Operations Assessment |
<p>| PRC-007-0  | Assuring Consistency of Entity Underfrequency Load Shedding Programs with Regional Reliability Organization’s Underfrequency Load Shedding Program requirements | 6/18/2007       | None identified                                                                | Lower – Medium        | Long Term Planning                               |
| PRC-008-0  | Implementation and Documentation of Underfrequency Load Shedding Equipment Maintenance Program | 6/18/2007       | None identified                                                                | Medium                | Long Term Planning                               |
| PRC-009-0  | Analysis and Documentation of Underfrequency Load Shedding Performance Following an Underfrequency Event | 6/18/2007       | None identified                                                                | Lower – Medium        | Operations Assessment                           |
| PRC-010-0  | Technical Assessment of the Design and Effectiveness of Undervoltage Load Shedding Program | 6/18/2007       | None identified                                                                | Lower – Medium        | Operations Assessment                           |
| PRC-011-0  | Undervoltage Load Shedding System Maintenance and Testing             | 6/18/2007       | None identified                                                                | Lower – Medium        | Long Term Planning                               |
| PRC-015-0  | Special Protection System Data and Documentation                       | 6/18/2007       | None identified                                                                | Lower – Medium        | Long Term Planning                               |
| PRC-016-0.1| Special Protection System Misoperations                                | 5/13/2009       | None identified                                                                | Lower – Medium        | Operations Assessment                           |</p>
<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
<th>Enforcement Date</th>
<th>Data Retention</th>
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<th>Violation Time Horizon</th>
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<tbody>
<tr>
<td>PRC-017-0</td>
<td>Special Protection System Maintenance and Testing</td>
<td>6/18/2007</td>
<td>None identified</td>
<td>Lower – Medium – High</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>PRC-018-1</td>
<td>Disturbance Monitoring Equipment Installation and Data Reporting</td>
<td>6/18/2007</td>
<td>Applicable entities retain Disturbance Data for three years.</td>
<td>Lower</td>
<td>Long Term Planning and Operations Assessment</td>
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<tr>
<td>PRC-019-1</td>
<td>Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection</td>
<td>7/1/2016</td>
<td>Six years</td>
<td>Medium</td>
<td>Long Term Planning</td>
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<tr>
<td>PRC-021-1</td>
<td>Under-Voltage Load Shedding Program Data</td>
<td>6/18/2007</td>
<td>Copy of data submitted for previous two years</td>
<td>Lower - Medium</td>
<td>Long Term Planning and Operations Planning</td>
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<tr>
<td>PRC-022-1</td>
<td>Under-Voltage Load Shedding Program Performance</td>
<td>6/18/2007</td>
<td>Two years</td>
<td>Lower - Medium</td>
<td>Operations Assessment</td>
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<tr>
<td>PRC-023-1</td>
<td>Transmission Relay Loadability</td>
<td>7/1/2010</td>
<td>M1, 2) Three years 3) Most recent documentation</td>
<td>Medium - High</td>
<td>Long Term Planning</td>
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<tr>
<td>PRC-023-2</td>
<td>Transmission Relay Loadability</td>
<td>7/1/2012</td>
<td>M1, M2, M3, M4, 5) Three years 6) Most recent documentation</td>
<td>Lower - Medium - High</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>PRC-024-1</td>
<td>Generator Frequency and Voltage Protective Relay Settings</td>
<td>7/1/2016</td>
<td>Three years or since last audit</td>
<td>R1, R2 Medium, R3, R4 Lower</td>
<td>R1, R2, R3 Long Term Planning, R4 Operations Planning</td>
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</tbody>
</table>

**Transmission Operations (TOP)**
<table>
<thead>
<tr>
<th>Standard</th>
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<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
</tr>
</thead>
</table>
| TOP-001-1a    | Reliability Responsibilities and Authorities | 11/21/2011       | 1) Current in-force document to show it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure reliability of its area  
2) 90 days of historical data  
3) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
4) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA,  
5) The CEA shall keep the last periodic audit report and all supporting compliance data | High                  | Real-time Operation                                                        |
| TOP-002-2.1b  | Normal Operations Planning                  | 9/13/2012        | 1) Current plans and a rolling 6 months of historical records  
2) Current plans and a rolling 6 months of historical records  
3) Current plans and a rolling 6 months of historical records  
4) 90 days of historical data current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence  
5) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
6) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA  
7) The CEA shall keep the last periodic audit report and all supporting compliance data | Medium                | Operations Planning                                                       |
<p>| TOP-003-1     | Planned Outage Coordination                 | 10/1/2011        | One calendar year                                                             | Medium – Pending      | Operations Planning          |</p>
<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
<th>Enforcement Date</th>
<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
</tr>
</thead>
</table>
| TOP-004-2| Transmission Operations                                    | 1/22/2009         | 1) 90 days of historical data  
2) Current, in-force policies and procedures  
3) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
4) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA,  
5) The CEA shall keep the last periodic audit report and all supporting compliance data. | High                  | Real-time Operation          |
| TOP-005-2a| Operational Reliability Information                       | 10/1/2011         | Not specified.                                                                 | Pending (Medium in prior version) | Operations Planning and Same-day Operations |
| TOP-006-2| Monitoring System Conditions                              | 10/1/2011         | 1) 90 days of historical data  
2) Current documents  
3) If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.  
4) Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the CEA,  
5) The CEA shall keep the last periodic audit report and all supporting compliance data. | Medium – Pending      | Real-time Operation          |
<p>| TOP-007-0| Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations | 6/18/2007         | Three months                                                                  | High                  | Real-time Operation          |
| TOP-007-WECC-1| System Operating Limits                                      | 7/1/2011         | Three years + current, or since last audit, whichever is longer              | High                  | Real-time Operation          |
| TOP-008-1| Response to Transmission Limit                             | 6/18/2007         | 90 days of historical data                                                    | High                  | Real-time Operation          |</p>
<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
<th>Enforcement Date</th>
<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
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<tr>
<td></td>
<td>Violations</td>
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<td>current documents</td>
<td>Medium</td>
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<td>TPL-001-0.1</td>
<td>System Performance Under Normal (No Contingency) Conditions (Category A)</td>
<td>5/13/2009</td>
<td>Not specified</td>
<td>High; subs are Medium and Lower</td>
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</tr>
<tr>
<td>TPL-001-4</td>
<td>Transmission System Planning Performance requirements</td>
<td>1/1/2015</td>
<td>R1 Current plus previous planning assessment. R2-R7 evidence since last compliance audit. R8 evidence for three years.</td>
<td>R1, R3-R6, R8 Medium, R2 High, R7 Low</td>
<td>Long Term Planning</td>
</tr>
<tr>
<td>TPL-002-0b</td>
<td>System Performance Following Loss of a Single Bulk Electric System Element (Category B)</td>
<td>10/24/2011</td>
<td>Not specified</td>
<td>High; R1 subs and R2 are Medium and Lower</td>
<td>Operations Planning</td>
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<tr>
<td>TPL-003-0a</td>
<td>System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)</td>
<td>4/23/2010</td>
<td>Not specified</td>
<td>Medium and Lower</td>
<td>Operations Planning</td>
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<tr>
<td>TPL-003-0b</td>
<td>System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)</td>
<td>6/20/2013</td>
<td>Not specified</td>
<td>High; R1 subs and R2 are Medium and Lower</td>
<td>Operations Planning</td>
</tr>
<tr>
<td>TPL-004-0</td>
<td>System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)</td>
<td>6/18/2007</td>
<td>Not specified</td>
<td>Medium</td>
<td>Operations Planning</td>
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<td>TPL-004-0a</td>
<td>System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)</td>
<td>6/20/2013</td>
<td>Not specified</td>
<td>Medium</td>
<td>Operations Planning</td>
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</table>

**Voltage and Reactive (VAR)**
<table>
<thead>
<tr>
<th>Standard</th>
<th>Title</th>
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<th>Data Retention</th>
<th>Violation Risk Factor</th>
<th>Violation Time Horizon</th>
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<tbody>
<tr>
<td>VAR-001-3</td>
<td>Voltage and Reactive Control</td>
<td>1/1/2014</td>
<td>12 months</td>
<td>R1, R2, R5, R7, R8, R9, R10, R12 High, R4, R6 Medium, R3, R11 Lower</td>
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</tr>
<tr>
<td>VAR-002-2b</td>
<td>Generator Operation for Maintaining Network Voltage Schedules</td>
<td>7/1/2013</td>
<td>M1, M2, M3, M4, M7,- Evidence for current year plus prior year M5, M6 - Evidence retained for current version of transformer data</td>
<td>R1, R2, R3, R5 Medium, R4 Lower</td>
<td>Real-time Operations</td>
</tr>
</tbody>
</table>
Appendix 4: GAGAS References

- Section 6.03 (pg. 124) – Reasonable Assurance. “In performance audits that comply with GAGAS, auditors obtain reasonable assurance that evidence is sufficient and appropriate to support the auditors’ findings and conclusions in relation to the audit objectives. Thus, the sufficiency and appropriateness of evidence needed and tests of evidence will vary based on the audit objectives, findings, and conclusions...Professional judgment assists auditors in determining...whether sufficient, appropriate evidence has been obtained to address the audit objectives.”

- Section 6.05 (pg. 125) – Audit Risk. “Audit risk is the possibility that the auditors’ findings, conclusions, recommendations, or assurance may be improper or incomplete, as a result of factors such as evidence that is not sufficient and/or appropriate.”

- Section 6.12 (pg. 128) – “During the planning, auditors should also...identify sources of audit evidence and determine the amount and type of evidence needed given audit risk and significance.”

- Section 6.56 (pg. 150) “Sufficiency is a measure of the quantity of evidence used for addressing the audit objectives and supporting findings and conclusions. Sufficiency also depends on the appropriateness of the evidence. In determining the sufficiency of evidence, auditors should determine whether enough appropriate evidence exists to address the audit objectives and support the findings and conclusions.”

- Section 6.60 (starting at pg. 151) – Appropriateness. “Appropriateness is the measure of the quality of evidence that encompasses the relevance, validity, and reliability of evidence used for addressing the audit objectives and supporting findings and conclusions.”

- Section 6.60 – 6.72 discuss the appropriateness and sufficiency of the evidence used to make audit determinations, excerpts are included below as examples:
  - 6.68 The following presumptions are useful in judging the sufficiency of evidence. The sufficiency of evidence required to support the auditors’ findings and conclusions is a matter of the auditors’ professional judgment.
    - The greater the audit risk, the greater the quantity and quality of evidence required.
    - Stronger evidence may allow less evidence to be used.
    - Having a large volume of audit evidence does not compensate for a lack of relevance, validity, or reliability.
  - 6.71 When assessing the sufficiency and appropriateness of evidence, auditors should evaluate the expected significance of evidence to the audit objectives, findings, and conclusions, available corroborating evidence, and the level of audit risk. The steps to assess evidence may depend on the nature of the evidence, how the evidence is used in the audit or report, and the audit objectives.
    - Evidence is sufficient and appropriate when it provides a reasonable basis for supporting the findings or conclusions within the context of the audit objectives.
    - Evidence is not sufficient or not appropriate when: (1) using the evidence carries an unacceptably high risk that it could lead the auditor to reach an incorrect or improper conclusion, (2) the evidence has significant limitations, given the audit objectives and intended use of the evidence, or (3) the evidence does not provide an adequate basis for addressing the audit objectives or supporting the findings and conclusions. Auditors should not use such evidence as support for findings and conclusions.
Appendix 5: Rules of Procedure references

Rules of Procedure

- Section 401.3 (pg. 22) – Compliance Enforcement: Data Access. “All Bulk Power System owners, operators, and users shall provide to NERC and the applicable Regional Entity such information as is necessary to monitor compliance with the Reliability Standards. NERC and the applicable Regional Entity will define the data retention and reporting requirements in the Reliability Standards and compliance reporting procedures.”

- Section 401.9 (pg. 24) – Records. “NERC shall maintain a record of each compliance submission, including Self-Reported, Possible, Alleged, and Confirmed Violations of approved Reliability Standards; associated Penalties, sanctions, Remedial Action Directives and settlements; and the status of mitigation actions.”

- Section 402.3 (pg. 27) – Information Collection and Reporting. “NERC and the Regional Entities shall implement data management procedures that address data reporting requirements, data integrity, data retention, data security, and data confidentiality.”

- Section 501.2.3-2.4 (pg. 46) – Entity Certification. “The NERC programs shall...Maintain process documentation [2.3]...Maintain records of currently certified entities [2.4].”

- Section 501.3.3.2 (pg. 47) – Delegation and Oversight. “Monitoring and oversight shall be accomplished through direct participation in the Organization Registration and Organization Certification Programs with periodic reviews of documents and records of both programs.”

- Section 502.2.1-2.2 (pg. 48) – Organization Registration and Organization Certification Program Requirements.

To ensure consistency and fairness of the Organization Registration and Organization Certification Programs, NERC shall develop procedures to be used by all Regional Entities and NERC in accordance with the following criteria:

- 2.1 NERC and the Regional Entities shall have data management processes and procedures that provide for confidentiality, integrity, and retention of data and information collected.

- 2.2 Documentation used to substantiate the conclusions of the Regional Entity/NERC related to Registration and/or Certification must be retained by the Regional Entity for (6) six years, unless a different retention period is otherwise identified, for the purposes of future audits of these programs.

- Section 502.2.4 (pg. 49) – Organization Registration and Organization Certification Program Requirements. “Copies of notes, draft reports, and other interim documents developed or used during an entity Certification evaluation or program audit shall be destroyed after the public posting of a final, uncontested report.”

- Section 606.6 (pg. 61) – Personnel Certification: Candidate Testing Mechanisms. “The Personnel Certification Program shall utilize policies and procedures that govern how long examination records are kept in their original format.”

- Section 1104 (pg. 80) – Annual NERC Business Plans and Budgets. “NERC shall also have the right to review from time to time, in reasonable intervals but no less frequently than every three years, the financial books and records of each Regional Entity having delegated authority in order to ensure that the documentation fairly represents in all material aspects appropriate funding of delegated functions.”
Appendix 2 to the NERC Rules of Procedure

- “Compliance Audit” means a systematic, objective review and examination of records and activities to determine whether a Registered Entity meets the Requirements of applicable Reliability Standards.
- “Notice of Possible Violation” means a notice issued by the Compliance Enforcement Authority to a Registered Entity that: (1) states a Possible Violation has been identified, (2) provides a brief description of the Possible Violation, including the Reliability Standard Requirement(s) and the date(s) involved, and (3) instructs the Registered Entity to retain and preserve all data and records relating to the Possible Violation.

Appendix 4C to the NERC Rules of Procedure (CMEP)

- Section 3.1.4.2 (pg. 8) – Scope of Compliance Audits: Period Covered. “The Registered Entity’s data and information must show compliance with the Reliability Standards that are the subject of the Compliance Audit for the entire period covered by the Compliance Audit...The Registered Entity will be expected to demonstrate compliance for the entire period described above. If a Reliability Standard specifies a document retention period that does not cover the entire period described above, the Registered Entity will not be found in noncompliance solely on the basis of the lack of specific information that has rightfully not been retained based on the retention period specified in the Reliability Standard."
- Section 3.8 (pg. 21) – Preliminary Screen. “The Compliance Enforcement authority shall maintain records of all Preliminary Screens.”
- Section 9.1 (pg. 40) – Records Management. “The Compliance Enforcement Authority records management policy shall provide for a routine and orderly process for the retention and disposal of electronic and paper records related to the Compliance Program, ensure verification of compliance with appropriate business, regulatory, and legal requirements and at a minimum conform to the data retention requirements of the Reliability Standards. The policy shall allow for the maintenance of records as required to implement the Compliance Program.”
- Section 9.2 (pg. 41) – Retention Requirements. “The Compliance Enforcement Authority records management policy will require that information and data generated or received pursuant to Compliance Program activities, including Compliance Audits, Self-Certifications, Spot Checks, Compliance Investigations, Self-Reports, Periodic Data Submittals, Exception Reporting, and Complaints, as well as a hearing process, will be retained for the longer of (i) five (5) years or (ii) any retention period specified in a Reliability Standard or by FERC or another Applicable Governmental Authority. The obligation to retain information and data commences upon the initiation of the Compliance Program activity that produces the data or information. If the information or data is material to the resolution of a controversy, the retention period for such data shall not commence until after the controversy is resolved.”

NERC ROP Appendix 5C

- Section 8.0 (pg. 15) – Approval or Disapproval of an Exception Request. “NERC shall provide to the Submitting Entity and to the Owner, if different, copies of any documents considered by the NERC review team in reaching its proposed decision, and any additional documents considered by the NERC President in reaching the final decision, that were not originally provided by, or have not previously been provided to, the Submitting Entity or Owner...Documentation used to substantiate the decision related to an Exception Request shall be retained by NERC for a minimum of seven (7) years or as long as the Exception is in effect, whichever is longer, unless a different retention period is otherwise identified.”
Appendix 6: Data Retention Survey Results

Question 3: Registered Function

<table>
<thead>
<tr>
<th>Function (check all that apply)</th>
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</thead>
<tbody>
<tr>
<td>RSG</td>
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<tr>
<td>RC</td>
</tr>
<tr>
<td>IA</td>
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<tr>
<td>PA/PC</td>
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<tr>
<td>TSP</td>
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<tr>
<td>BA</td>
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<td>RP</td>
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<td>TO</td>
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<td>DP</td>
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<td>LSE</td>
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<tr>
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Question 4: Region and Audit Cycle

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<tr>
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<th>3 Year Audit Cycle</th>
<th>6 Year Audit Cycle</th>
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<tr>
<td>FRCC</td>
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<td>8</td>
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<tr>
<td>MRO</td>
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<td>26</td>
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</tr>
<tr>
<td>NPCC</td>
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<td>TRE</td>
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<td>5</td>
</tr>
<tr>
<td>WECC</td>
<td>9</td>
<td>33</td>
<td>14</td>
</tr>
</tbody>
</table>
**Question 5: Current Entity Data Retention Policy**

- **77.1%**: We have a data retention policy that covers all our data retention obligations, to include NERC.
- **11.1%**: We have a data retention policy that only covers NERC obligations.
- **8.3%**: We do not have a retention policy related to NERC requirements.
- **3.5%**: Not Applicable

**Question 6: Do you have a data historian for SCADA type data (a software application for archiving time-based data)?**

- **79.2%**: Yes
- **13.9%**: No
- **6.9%**: Not Applicable
Question 7: Which do you consider the most challenging or problematic issue with regard to data retention for compliance (where 1 is the most problematic and 5 is the least troublesome)?

![Survey Results Chart]

Question 8: What is the appropriate data retention for each of the following classes of information?

![Data Retention Chart]
Question 9: Which should be the priority considerations for data retention?

![Bar Chart showing survey results for Question 9]

- Impact on reliability: Very Important 122, Somewhat Important 13, Not Important 2, Don't Know or Unsure 6
- Amount of data (periodicity and number of pieces of information): Very Important 47, Somewhat Important 69, Not Important 15, Don't Know or Unsure 10
- Time between audits: Very Important 58, Somewhat Important 46, Not Important 33, Don't Know or Unsure 6
- Type of media (paper, data): Very Important 26, Somewhat Important 74, Not Important 38, Don't Know or Unsure 5
- Cost of storage to the Registered Entity: Very Important 38, Somewhat Important 73, Not Important 24, Don't Know or Unsure 8
- Difficulty to access: Very Important 61, Somewhat Important 62, Not Important 14, Don't Know or Unsure 6
- Information collected as part of an investigation: Very Important 89, Somewhat Important 42, Not Important 2, Don't Know or Unsure 10
- Consistency across multiple standards: Very Important 81, Somewhat Important 51, Not Important 5, Don't Know or Unsure 5
- Only current in-force documents rather than historical document maintenance: Very Important 67, Somewhat Important 56, Not Important 10, Don't Know or Unsure 9

Question 10: Would the approach above be preferable to the present approach of retaining data as outlined in each standard?

![Pie Chart showing survey results for Question 10]

- Yes: 74.3%
- No: 21.4%
- Not Applicable: 4.3%
Question 13: Do you feel the RSAWs are sufficiently clear as to type, format, and scope of evidence?

- Yes: 57.7%
- No: 39.4%
- Not Applicable: 2.9%

Question 14: Is the information requested in RSAWs consistent with the requirements in the standard and ask the correct questions to determine compliance?

- Yes: 69.3%
- No: 26.3%
- Not Applicable: 4.4%
Question 17: With regard to the data you provided prior to the audit, which best represents your opinion or observations on how data was used.

[Graph showing the percentage of responses]

Question 18: With regard to the data requests during the audit, which best represents your opinion and observations?

[Bar chart showing the percentage of responses]
Question 19: In general, was the scope of data requested in the pre-audit submittal consistent with the evidence expected during the actual audit?

![Pie chart showing response to Question 19]

- 83.9% Yes
- 8.8% No
- 7.3% Not Applicable

Question 21: How would you classify the amount of data requested during Compliance Investigations?

![Pie chart showing response to Question 21]

- 34.6% The amount of data requested and time to respond was reasonable.
- 44.1% There was one data request but we had difficulty meeting amount of data requested.
- 20.6% There were multiple data requests and it was difficult to meet all the requests for data.
- 0.7% Not applicable. We have not been involved in any investigations.
Question 22: How would you classify the amount of data requested during Compliance Investigations?

- 50.0%: The amount of data requested and time to respond was reasonable.
- 42.6%: There was one data request but we had difficulty meeting amount of data requested.
- 5.1%: There were multiple data requests and it was difficult to meet all the requests for data.
- 2.2%: Not applicable. We have not been involved in any investigations.
Appendix 7: Common data types

- **Real-time operating data**
  - SCADA
  - One-second or less disturbance data
  - ACE, frequency, Bias

- **Direct communication**
  - Voice logs
  - Email
  - Memos

- **Video recording**
  - Access video recordings
  - Access logs - computerized, video, or manual logging - electronic capture of video images, electronic logs, log book or sign-in sheet

- **Training communication**
  - Posters
  - Brochures
  - Rosters
  - Training materials

- **Logs**
  - Operator

- **PRAs and security vetting documents**

- **Modeling data**
  - Steady-state modeling and simulation data, system data
  - Actual and forecast customer data

- **Testing and inspection evidence**

- **Long-term planning documents**
  - Procedures with review periods
  - Lists
  - Procedure guidelines
  - Policies
  - MOUs
  - Annual assessments
Data Retention
White Paper

May 25, 2017
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Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system (BPS)\(^1\) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC’s area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC’s jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity boundaries, as shown in the map and corresponding table below.

![Map of Regional Entities]

<table>
<thead>
<tr>
<th>FRCC</th>
<th>Florida Reliability Coordinating Council</th>
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<tbody>
<tr>
<td>MRO</td>
<td>Midwest Reliability Organization</td>
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<tr>
<td>NPCC</td>
<td>Northeast Power Coordinating Council</td>
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<td>RF</td>
<td>ReliabilityFirst</td>
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<td>SERC</td>
<td>SERC Reliability Corporation</td>
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<td>SPP-RE</td>
<td>Southwest Power Pool Regional Entity</td>
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<td>TRE</td>
<td>Texas Reliability Entity</td>
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<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
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As has been presented in the concept papers for the Reliability Assurance Initiative (RAI), NERC and the Regional Entities (known collectively as the ERO Enterprise) are moving to a risk-based strategy, particularly in the areas of Compliance and Enforcement. At the start of 2013, the ERO Enterprise assembled an advisory group to provide input and advice for modification of existing NERC Reliability Standard data retention requirements. The data retention team is comprised of representatives from NERC and the NERC Compliance and Certification Committee (CCC).

Beginning in 2013, the data retention team began reviewing and analyzing current data retention requirements and soliciting industry feedback on current data retention requirements. This white paper presents the information reviewed by the team and makes recommendations for changes to current guidance documents, future NERC Reliability Standard development, and auditing processes.

\(^1\) Pursuant to the Energy Policy Act of 2005, NERC and FERC have jurisdiction over users, owners, and operators of the BPS. Section 215 of the Federal Power Act defines BPS as the facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) and electric energy from generation facilities needed to maintain transmission system reliability. FERC has recognized that users, owners, and operators of the BPS are users, owners and operators of the Bulk Electric System (BES). The definition of BES went into effect July 1, 2014. See NERC Glossary of Terms available at: http://www.nerc.com/files/glossary_of_terms.pdf. See also, 146 FERC ¶ 61,199, March 20, 2014. Nothing in this document limits the jurisdictional authority of NERC and FERC pursuant to the Energy Policy Act of 2005 and Section 215 of the FPA.
Executive Summary

This white paper is a product of the data retention team’s analysis and explores possible options for establishing uniform tools and applications and standardizing evidence retention requirements across the ERO Enterprise to promote consistency in demonstrating compliance. These options should provide improvements that support reliability and ensure that resources allocated by the ERO Enterprise and registered entities are commensurate with the potential risks of noncompliance to reliability. This white paper recommends that NERC modify data retention requirements so that the burden of producing records necessary to demonstrate compliance is commensurate with the risk to the reliability of the BPS.

The data retention team also recommends including in new Reliability Standards a consistent data retention period of either a rolling 6-months for high-volume data,\(^2\) or a 4-year retention period for all other data, with two specific exceptions: 1) Standards requiring a current program or procedure, which would be limited to the currently effective version with a revision history specifying changes and dates of review; and 2) Standards requiring testing at intervals,\(^3\) which would require the retention of the last full testing record and evidence of recurrence. In addition, this white paper recommends simplifying data requests by including as a part of the ERO Compliance Auditor Manual and Handbook a recommendation that, regardless of the data retention requirements of the Standard and time between Compliance Audits, auditors focus sampling to the most recent two years. This recommended method of sampling would be more efficient and less burdensome for registered entities and the ERO Enterprise. By instituting the recommended method of sampling, the ERO Enterprise and registered entities could reallocate resources to areas of greater risk to the reliability of the BPS.

Feedback on the recommendations outlined in this white paper will focus and refine the ultimate data retention requirements and auditor sampling methodology.

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\(^2\) “High-volume data,” as used herein, refers to electronic data sets and files, paper documents, or audio recordings with sizes making it cost- or space-prohibitive to gather, maintain, track, and provide the data to auditors within a reasonable period. Examples of high-volume data could be access logs, video surveillance tapes, or voice and telephone recordings.

\(^3\) For example, PRC-005 requires a registered entity to provide evidence that its distinct maintenance activities have been performed within the intervals identified by the registered entity in its Protection System Maintenance Program.
Introduction

Purpose

The ERO Enterprise assembled a working team to assess the data retention requirements of the NERC Reliability Standards, Rules of Procedure, and the current guidance on data requests to registered entities. The goal of this effort was to determine the burdens of document retention and compliance data requests in order to balance those factors with potential risk of noncompliance to the reliability of the BPS.

The purpose of this white paper is to provide background and technical rationale for proposed revisions to the data retention requirements in new and revised NERC Reliability Standards and to the methodology of Compliance Audit and Spot Check data sampling requests. The goal is to minimize the Compliance Enforcement Authority (CEA) and registered entity resources used for gathering, storing, and producing data while maintaining reasonable assurance of compliance with the effective NERC Reliability Standards and reliability of the BPS.

The data retention team:

- Identified and evaluated current data retention requirements;
- Recommended improvements to reduce the data-maintenance burdens on registered entities;
- Provided guidance regarding the levels of data necessary to support proof of compliance;
- Recommended revised data retention requirements to be commensurate with risk to the BPS; and
- Recommended methods of sampling that are more efficient and less burdensome for registered entities.

There is no current consistent data retention period prescribed by the Commission or NERC applicable to all Reliability Standards. There are different requirements for the length of time registered entities must keep identical types of data for certain Reliability Standards. The ERO Enterprise has considerable flexibility to determine and identify how long a registered entity must retain evidence to show compliance. This flexibility allows the ERO Enterprise to consider altering data retention requirements and data sampling methodologies.

This document describes current retention requirements for data sampling techniques and provides justification for, and proposes guidance on, data retention requirements within the NERC Reliability Standards and requirements, both through the standards review process for existing Standards and through standards development for future Standards.

Background

In November 2012, the ERO Enterprise began to develop the RAI, a multi-year effort to identify and implement changes that enhance the effectiveness of the Compliance Monitoring and Enforcement Program (CMEP). The experience of the past several years demonstrates that it is not practical, effective, or sustainable for the ERO Enterprise to monitor and control all compliance to the same degree and to treat all noncompliance with the same level of process and evidentiary requirements.

RAI is the ERO Enterprise’s strategic initiative to transform the current compliance and enforcement program into one that is forward-looking, focuses on high reliability risk areas, and reduces undue administrative burden on registered entities. The goal of RAI is to implement a risk-based program for compliance monitoring and enforcement of Reliability Standards, which provides reasonable assurance through compliance monitoring, applies appropriate discretion in enforcement, and ensures a feedback loop for the improvement of Reliability Standards.

Current data retention approach

At the beginning of NERC’s CMEP, the ERO Enterprise took a prescriptive approach to data retention. Each registered entity was required to have historical documents for the entire audit period as evidence of compliance for each applicable measure included in a Reliability Standard.
Each registered entity is required to provide to NERC and its applicable Regional Entity information necessary to monitor compliance with the NERC Reliability Standards. Each Compliance Audit includes a review of supporting documentation and evidence used by the registered entity. Each CEA has the authority to collect the necessary information to determine compliance and develop processes for gathering data from the BPS owners, operators, and users it monitors.

The NERC Rules of Procedure and the NERC Reliability Standards describe the retention periods for information. The audit review period is typically every three or six years, depending upon the functional registration of the registered entity. In addition, registered entities must retain and provide historical documents for investigations resulting from complaints or events. Certain NERC Reliability Standards contain specific provisions relating to document retention. In some cases, the document retention period is less than the three- or six-year audit period because there would be an “undue burden due to the volume of the data or information required.” In other instances, the NERC Reliability Standards require retention only of the current, in-force version of a policy, plan procedure, or other singular document.

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5 NERC Standards Process Manual at 6 (Sept. 2010) (stating that there is to be a section in each Standard for Evidence Retention).

6 NERC Bulletin on Data Retention Requirements at 1 (May 20, 2011). For example, NERC recognizes that retaining three-second data from an Energy Management System (EMS) or a Supervisory Control and Data Acquisition (SCADA) system for every three or six years would pose an undue burden due to the volume of records to be retained. In such cases, the audit team will look to the NERC Reliability Standard for guidance regarding a reasonable data retention period.

Chapter 1 - Methodology

Current data retention requirements and guidance

Beginning in 2013, the data retention team conducted a review of current in-force documents, processes, and procedures to determine the full scope of data retention requirements. The data retention team began reviewing and analyzing the data retention requirements in all currently-enforceable and NERC Board of Trustee approved NERC Reliability Standards, the NERC Rules of Procedure, and guidelines for auditing included in the Generally Accepted Government Auditing Standards (GAGAS). Finally, the data retention team reviewed the ERO Enterprise Compliance Auditor Manual and Handbook (Auditor Manual).

Section 215 of the Federal Power Act requires the ERO to develop mandatory and enforceable reliability standards, which are subject to Commission review and approval. The data retention team reviewed both Commission-approved standards and standards adopted by the NERC Board of Trustees. The team reviewed 136 standards, each including multiple requirements, within the 14 families of NERC Reliability Standards. Each requirement was analyzed to determine the: 1) enforcement date; 2) the currently proscribed data retention period; 3) the Violation Risk Factor (VRF); and 4) the Violation Time Horizon. A table covering these factors is included as Appendix 3. Each of the above-listed factors were considered by the data retention team in determining what an appropriate but consolidated and efficient data retention period may be for each kind of evidence. The team then compared the types of evidence required to determine compliance by standard to identify any existing consistencies and the type of data with the risk posed by a violation of the Standard. These determinations formed the basis of the recommended data retention periods, which were then included with a survey to representatives from registered entities to confirm whether these periods would be technically supportable.

Relevant auditor guidance is located within the following documents: 1) ERO Enterprise Compliance Auditor Manual; 2) Compliance Auditor Role Expectations Guide; 3) GAGAS; 4) Institute of Internal Auditors International Professional Practices Framework (IIAIPPF); 5) Public Company Accounting Oversight; and 6) NERC’s Rules of Procedure including Appendix 4C NERC Compliance Monitoring and Enforcement Program (CMEP) Sec. 3.1. The full listing of references within GAGAS for reviewing evidence is included in Appendix 4. The Manual currently consists of three primary parts: the Handbook, the Checklist, and the Glossary of Terms. Additional revisions under development include a section on sampling methodology.

As various RAI projects have evolved, the data retention team continued to evaluate if any programs, projects, or pilots either influenced its recommendations for retention, or could be affected by the recommendations of the team.

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10 The data retention team did not review standards still in development, although recommendations from this white paper will be forwarded to Standard Drafting Teams for future use.
Responses from industry to the Data Retention Survey

On December 4, 2013, the team sent a data retention survey to CCC representatives. The survey focused on industry experience and feedback on data retention requirements and Reliability Standard Audit Worksheets (RSAWs).

The team received 155 unique individual responses representing nearly 700 registered functions. The full results and responses to the Data Retention Survey are included in Appendix 6. The data retention team reviewed the responses to support the recommendations outlined within this white paper and to determine how registered entities are affected by current data retention requirements. This effort should allow the ERO Enterprise to focus its efforts on those areas presenting the greatest burden to registered entities, without introducing risk to the reliability of the BPS.
Chapter 2 - Results

Current data retention requirements and guidance

The only mandatory and enforceable components of a Reliability Standard are the: 1) applicability; 2) requirements; and the 3) effective dates. Any additional items are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to registered entities concerning how the CEA will assess compliance.

The NERC Reliability Standards do not have a consistent approach to evidence retention—different retention periods apply to various requirements and data types. For example, BAL-001-0.1a requires a one-year retention period for real-time operating data and VAR-002-2b requires two years of real-time operating data. COM-001-1.1 requires a 90-day retention of operator logs. According to IRO-006-5, if the records are audio recordings, they have a 90-day retention but if documented transcripts then it should be 12 months. MOD-028-2 requires retaining data for 12 months for seven of its requirements, but either 14, 30, or 60 days for two other requirements.\(^{11}\)

There are no specific references in any relevant auditor guidance as to how much data or what age of data to review to confirm compliance. The Auditor Manual does not contain any size-related requirements for sampling data. In fact, the Auditor Manual has included in its Action Item Tips & Techniques section that “available evidence may be limited by data retention requirements of the Reliability Standard or NERC guidance.” According to GAGAS, it is the auditor’s professional judgment as to whether evidence is sufficient to address the audit objectives.\(^{12}\)

As with the other current references to data retention, the Rules of Procedure also do not include any guidance on specific retention periods for registered entities. The NERC Rules of Procedure do reference amounts of time for either Regional Entity or NERC retention. The full listing of references within the NERC Rules of Procedure for reviewing evidence is included in Appendix 5. The Rules of Procedure leave the assignment of data retention and reporting requirements to NERC or the Regional Entity.\(^{13}\)

Responses from industry to the Data Retention Survey

Respondents to the Data Retention Survey included representatives from 135 distinct entities including Independent System Operators, small cooperatives, city utilities, dispersed power generators, and trades associations. The majority of registered entity industry respondents were on a six-year audit cycle. In addition, the survey responses indicated that almost 80% of the registered entities had a data retention policy that covered all data retention obligations and had a data historian for archiving time-based data (e.g., SCADA).

Overview

The survey feedback, for the most part, confirmed the industry’s interest in BPS reliability. The responses had the common recommendation that whatever the changes may end up being, they should be simple, intuitive, standardized, and focused on reliability. The responses voiced a frustration and opinion that the focus of auditor data requests and NERC Reliability Standards data retention requirements are on proving compliance and not enhancing reliability. In addition, commenters remarked that data requirements should be more accordant with RAI and should be moving away from zero tolerance issues and towards a focus on internal processes and continuous improvement.

\(^{11}\) The full listing of current and pending NERC Reliability Standards with summarized data retention requirements is included in Appendix 3.

\(^{12}\) The full listing of references within GAGAS for reviewing evidence is included in Appendix 4.

\(^{13}\) See NERC Rules of Procedure at Section 401.3, P22.
Registered entity concerns with current data retention policies

The survey results listed the following three most challenging or problematic issues with regard to data retention for compliance:

- The differing retention periods between the Standards.
- Requests at Compliance Audits and Spot Checks for data that is no longer relevant.
- The volume of data that entities are required to retain and provide.

Nearly all of the responses supported modifications to the current data retention policies. Those that preferred to stay with the status quo did so out of a concern that changes would require additional financial and staffing resources, not because the current requirements are the best option.

One commenter reported that its Regional Entity tells them to save everything between audits even though the Standards lay out different retention requirements. Another comment stated that auditors told the entity to save data after an audit, but then was never contacted about how long to keep that data. Some entities stated that auditors had requested data outside of the retention periods stated in the Standards. For example, the Standard requires keeping records of "system events related to cyber security" for 90 days but then an auditor expected the entity to keep those records for three years.

A common theme was the belief that any changes need to be forward-looking and considered in a reliability context. Registered entities voiced a desire to focus on current practices and policies instead of historical documents, which may not have been relevant for several years. One commenter presented the example that if there are data gaps five years in the past, these are likely to be significantly less relevant to reliability concerns if all data is subsequently up-to-date and continues to be collected going forward.

Similarly, gaps in administrative documents such as missing signatures may be irrelevant to current risk to reliability, if the current supporting documents are complete. Industry responses did recommend exceptions for data and documents related to events and compliance investigations.

Registered entity concerns with current RSAWs

As Reliability Standard Audit Worksheets (RSAWs) are the primary mechanism to collect data for audits, compliance contacts were surveyed on their observations and experiences with RSAWs. Outlined below is a distillation of the survey comments:

- The most predominant comment was that the RSAWs differed from the Reliability Standard, that the questions asked did not always line up with the Standard, or that the questions were not the most precise way to demonstrate compliance.
- Several respondents noted differences among Regions and auditors in the use and expectations of RSAWs and data format.
- Several respondents felt NERC should provide examples of acceptable evidence (not the only way to demonstrate compliance, but acceptable ways).
- RSAWs could be simpler and easier to fill out.
- CIP data requests for audits differ from what the RSAW contains. The Registered Entity often finds out after data submission that data is preferred in a different format.
- There is not a simple way to flag those things not applicable to the Registered Entity and capture that information for future audits and self-certifications.
- RSAW changes make it difficult to keep up.
• There should be a mechanism to attest to compliance directly in the RSAW for those things that occur infrequently or by exception.

• RSAWs should be developed along with the Reliability Standard and receive industry input.

• Additional data requests during an audit point to a problem with the RSAW, these additional data requests should be tracked to provide feedback to the RSAW improvement process.

• There are redundant questions in RSAWs.

The CCC has a separate RAI team working on suggested RSAW improvements. The raw survey comments were provided to this team.
Chapter 3 – Recommendations

The data retention team is targeting the recommendations contained in this section to the ERO Enterprise and auditing staff. The team does not intend these recommendations to instruct, pressure, or influence a registered entity to alter its preexisting document retention policies. Registered entities are often required to meet several different requirements for data retention. In addition to NERC Standard compliance, entities may be responsible to the Securities and Exchange Commission (SEC) or FERC. Entities may save certain data for long-term modeling or concerns about potential litigation. The ERO Enterprise data sampling recommended periods will not change if an entity retains documents, data, or information longer than the recommended periods, i.e. the scope of the data request will not go beyond recommended bounds, regardless of what data may be available at the entity.

The data retention team also addresses industry concerns that changes to the data retention requirements would be unduly burdensome, both in terms of financial and staffing considerations. Since the resulting requirement should be less extensive or simpler than that currently in place, any current policies would not need replacement. As stated above, data sampling requests will be limited to the data retention periods NERC sets, therefore entities will have time to either update their internal policies or leave them as is.

Based on the results of the comprehensive policy review, the data retention team recommends that NERC modify data retention requirements so that the burden of producing records necessary to demonstrate compliance is commensurate with the impact to the reliability of the BPS. Specifically, changes will be necessary in NERC Reliability Standard and RSAW development, as well as in audit or spot check data sampling.

Standard Development

Survey responses focused on clarity and consistency within the NERC Reliability Standards as primary areas of concern.14 The data retention team took this feedback into account and recommends all new Standards receive a default four-year data retention period. This four-year period will exclude the following:

- Voice and audio recordings, which will continue to be a 90-day rolling retention period.
- High-volume data, which would be restricted to a six-month rolling retention period.
- Standards requiring a current program or procedure, which would restrict to the currently effective version with a revision history specifying changes and dates of review.
- Standards requiring testing intervals (e.g. PRC-005), which would restrict to the most recent full testing records with evidence of previous testing intervals.

If current Reliability Standards are silent as to a data retention period, then the four-year or six-month data retention period should be used.

The data retention team is not recommending changing Standards slated for retirement. The Standards development teams will update existing Standards when they come up for review. This recommended change to the Standards will allow entities to set an automatic archival date for data, which should reduce storage space and data retention costs.

Auditor data sampling

Current guidance within the Auditor Manual states that registered entities must continue to demonstrate compliance for the entire audit period; however, the Auditor Manual does not define how the auditor should determine compliance with the NERC Reliability Standards.

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14 See Appendix 6 Question 10.
Many industry concerns, as reflected in the survey responses, may be alleviated by incorporating the data retention white paper as a reference in the Auditor Manual, and issuing guidance to both the auditors and registered entities explaining how retention periods would apply in a Compliance Audit or Spot Check setting.

Guidance to auditors will need to make clear that while an entity may choose to retain some information for a longer period, the auditor requests should be limited to the data retention periods as established by NERC.

The data retention team recommends adding language to Section 03-0101 Preliminary Documentation review Action Item Tips & Techniques (figure 1), stating that, in general, auditors should focus their sampling of data to the most recent two years, unless the data sample would be statistically too small or irregularities are identified in the initial samples.

This limit would not apply to activity-based compliance that verifies periodic activities extending beyond the recommended two years or the audit period. This does not mean the auditor cannot sample and verify data throughout the whole audit period when, in the auditor’s professional judgment, it is necessary to confirm compliance.

To promote consistency across the ERO Enterprise, NERC staff should continue to work with the Regional Entity audit staffs to develop a standard data-sampling methodology. This document should address evaluating the quality of implemented controls and statistically defensible data sample sizes and windows. This methodology should be shared with the industry so audited entities can better understand how to demonstrate compliance strategies. Moreover, implementing a consistent approach to sampling data may help address the perception and concerns expressed in the survey responses that “data requests appear[] to go beyond what was required in the standard and RSAW.”

Current RAI compliance activities are moving auditors to a risk-based (as opposed to compliance-based) view of monitoring. Auditors will continue to use professional judgment when requesting information older than two years. Auditors should recognize that with time comes reduced relevance, changing technologies, changing thresholds of evidence, changing regulatory interpretations, and an entity’s constant efforts to improve compliance performance. Finally, the Auditor Manual already includes sections detailing what should be included as a part of the working papers created during the audit.

Some of the information included in the working papers details data sampling and requests made during the audit, and Regional Entity audit processes. After instituting the changes to Standards and guidance to auditors, the ERO Enterprise should conduct a two-year review of these working papers, and compare them among Regional Entities in order to check for consistency and make any necessary further improvements.
Chapter 3 – Recommendations

Risk-based Enforcement

In order to implement fully a risk-based approach for compliance monitoring and enforcement, the current program is evolving more explicitly around the risk to reliability. Three goals of the RAI compliance monitoring program reinforce recommendations included in this white paper:

- Compliance monitoring should shift to using standard, risk-based audit practices similar to other industries.
- Audit scoping based on a standard approach to assessing an entity’s risk to reliability.
- Processes to allow lower-risk violations to stay in compliance space.

Beginning in November 2013, the ERO Enterprise implemented the first phase of the pilot program for Enforcement Discretion to identify minimal risk issues that registered entities would record and mitigate without triggering an enforcement action. The RAI program includes a project designed to develop guidelines for exercise of greater discretion in identifying when noncompliance requires formal enforcement action. The data retention team recommends focusing efforts on registered entities’ needs for a clearer understanding of what constitutes a higher risk\(^\text{15}\) that would require addressing noncompliance within the enforcement process.

To align data retention requirements to the risk-based goals of RAI, the data retention team recommends restricting duration of possible instances of noncompliance to the audit period. For example, if an entity has no evidence it ever complied with a NERC Reliability Standard, the duration period would default to the audit period. This recommendation aligns with the understanding that the relevance of noncompliance to reliability of the BPS decreases with time, and enforcing a duration of noncompliance past the most recent audit does not increase reliability or provide any additional protection to the BPS. Penalties for such violations should depend more on the risk of the violation than on its stated duration, in order to realize the deterrent value of monetary sanctions.

RSAW Improvements

To support consistency and reliability, the ERO Enterprise should establish an online resource with examples of acceptable evidence. The examples would not be the only ways to demonstrate compliance, but would provide tangible guidance to both the registered entities and auditors.

In addition, the ERO Enterprise should provide guidance to registered entities and auditors on alternative forms of compliance demonstration, such as attestations, to accommodate previously retained but deleted or archived data. Finally, there should be a method of providing feedback on RSAWs and auditing/spot-check processes to NERC and ensure there is a formal review of that feedback, as well as responsive recommendations from the ERO Enterprise.

Compliance communication tools redesign

Currently underway is the redesign of certain compliance communication tools. NERC and the Regional Entities are coordinating to provide formal and documented processes for creating and reviewing RSAWs. These improvements should produce more consistent audit processes for registered entities. In addition, the new processes will provide for an initial release of a draft RSAW in conjunction with the release of Reliability Standards for ballot and interaction between Standards and Compliance personnel during the drafting of Reliability Standards. In addition, NERC is developing a revised RSAW template to provide more complete information about audit procedures and evidence to registered entities.

\(^{15}\) Higher risk issues generally involve or result in: (a) extended outages, (b) loss of load, (c) cascading blackouts, (d) vegetation contacts, (e) systemic or significant performance failures, (f) intentional or willful acts or omissions, (g) gross negligence, or (h) other misconduct.
These new processes were announced within the ERO and to industry during the first quarter of 2014 and are expected to be fully implemented by the end of 2014.

**Required next steps**

There are no necessary changes to either the NERC Rules of Procedure or current and retired NERC Reliability Standards. The completed white paper will be presented to the CCC and provided as a reference to the RAI Auditor Manual Task Force and NERC Standards Department.
Chapter 4 - Conclusion

The data retention team identified and evaluated current data retention requirements and has used this white paper to recommend improvements to reduce the data-maintenance burdens on registered entities. The foundational principle of RAI is that it is not practical, effective, nor sustainable to monitor all compliance to the same degree. To this end, the future of registered entity data retention to demonstrate NERC compliance should not be retention for retention’s sake, but instead consistent with associated risk. Improvement will come in the form of incorporating consistent retention requirements into the standards development process and applying consistent ERO Enterprise-wide risk-based compliance monitoring practices.

While registered entities do need evidence to demonstrate compliance, the type of evidence and the retention period should match the updated RAI audit approach with the ultimate objective of assuring reliability. In implementing such measures, the ERO Enterprise and registered entities could reallocate resources to areas of greater risk to the reliability of the BPS. Feedback on the recommendations outlined in this white paper will focus and refine the ultimate data retention requirements and auditor sampling methodology. The approach to data retention improvements outlined herein utilizes flexibility in the audit approach and does not rely on changes to current NERC Reliability Standards or Rules of Procedure.
Information only
NERC is required to submit a compliance filing in response to the Federal Energy Regulatory Commission (FERC) directive on Reliability Standard BAL-002-2 to revise the Violation Risk Factor (VRF) designations for Requirements R1 and R2 from “medium” to “high.” A compliance filing will be submitted in response to this directive.

Background
On January 19, 2017, FERC issued Order No. 835 approving BAL-002-2 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event). In its order, FERC also directed one modification to the standard, a report on data collected in relation to implementation of BAL-002-2, and a compliance filing to modify VRF designations for Requirement R1 and R2 of the standard. FERC directed this modification to VRFs, stating that “violation of Requirement R1 jeopardizes system frequency”...[and]...“the fundamental connection between Requirements R1 and R2 creates a significant role in maintaining reliability.” See, Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, Order No. 835, 158 FERC ¶ 61,030, PP 65-68 (2017).

Additional Information
A link to the FERC order is included here for reference:

Order No. 835 Approving Reliability Standard BAL-002-2
Standards Committee Expectations
Approved by Standards Committee January 12, 2012

Background
Standards Committee (SC) members are elected by members of their segment of the Registered Ballot Body, to help the SC fulfill its purpose. According to the Standards Committee Charter, the SC’s purpose is:

In compliance with the NERC Reliability Standards Development Procedure, the Standards Committee manages the NERC standards development process for the North American-wide reliability standards with the support of the NERC staff to achieve broad bulk power system reliability goals for the industry. The Standards Committee protects the integrity and credibility of the standards development process.

The purpose of this document is to outline the key considerations that each member of the SC must make in fulfilling his or her duties. Each member is accountable to the members of the Segment that elected them, other members of the SC, and the NERC Board of Trustees for carrying out their responsibilities in accordance with this document.

Expectations of Standards Committee Members
1. SC Members represent their segment, not their organization or personal views. Each member is expected to identify and use mechanisms for being in contact with members of the segment in order to maintain a current perspective of the views, concerns, and input from that segment. NERC can provide mechanisms to support communications if an SC member requests such assistance.

2. SC Members base their decisions on what is best for reliability and must consider not only what is best for their segment, but also what is in the best interest of the broader industry and reliability.

3. SC Members should make every effort to attend scheduled meetings, and when not available are required to identify and brief a proxy from the same segment. Standards Committee business cannot be conducted in the absence of a quorum, and it is essential that each Standards Committee make a commitment to being present.

4. SC Members should not leverage or attempt to leverage their position on the SC to influence the outcome of standards projects.

5. The role of the Standards Committee is to manage the standards process and the quality of the output, not the technical content of standards.
Standards Committee Meeting Dates and Locations for 2017

The time for face-to-face meetings is based on the ‘local’ time zone. The time specified for all conference calls is based on Eastern Time.

- January 18, 2017 Conference Call (1:00 - 4:00 p.m.)
- March 15, 2017 WECC (10:00 a.m. – 3:00 p.m.)
- April 19, 2017 Conference Call (1:00 - 4:00 p.m.)
- June 14, 2017 Atlanta (10:00 a.m. – 3:00 p.m.)
- July 19, 2017 Conference Call (1:00 - 4:00 p.m.)
- September 7, 2017 MRO (10:00 a.m. – 3:00 p.m.)
- October 18, 2017 Conference Call (1:00 - 4:00 p.m.)
- December 6, 2017 Atlanta (10:00 a.m. – 3:00 p.m.)

This schedule was designed so that the SCPS SC subcommittee face-to-face meetings will occur the day before and the PMOS SC Subcommittee will occur face-to-face the mornings of the SC meetings from 8:00 a.m. – 9:45 a.m. Scheduling of subcommittee face-to-face meetings is handled by the chairs of the subcommittees in consultation with the subcommittees’ members and NERC staff.
## Standards Committee

2017 Segment Representatives

<table>
<thead>
<tr>
<th>Segment and Term</th>
<th>Representative</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Chair</strong> 2016-17</td>
<td>Brian Murphy</td>
<td>NextEra Energy, Inc.</td>
</tr>
<tr>
<td></td>
<td>Senior Attorney</td>
<td></td>
</tr>
<tr>
<td><strong>Vice-Chair</strong> 2016-17</td>
<td>Michelle D’Antuono</td>
<td>Occidental Energy Ventures, LLC</td>
</tr>
<tr>
<td></td>
<td>Manager, Energy</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 1-2016-17</strong></td>
<td>Laura Lee</td>
<td>Duke Energy</td>
</tr>
<tr>
<td></td>
<td>Manager of ERO Support and Event Analysis, System Operations</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 1-2017-18</strong></td>
<td>Sean Bodkin</td>
<td>Dominion Resources Services, Inc.</td>
</tr>
<tr>
<td></td>
<td>NERC Compliance Policy Manager</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 2-2016-17</strong></td>
<td>Ben Li</td>
<td>Independent Electric System Operator</td>
</tr>
<tr>
<td></td>
<td>Consultant</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 2-2017-18</strong></td>
<td>Charles Yeung</td>
<td>Southwest Power Pool</td>
</tr>
<tr>
<td></td>
<td>Executive Director Interregional Affairs</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 3-2016-17</strong></td>
<td>Scott Miller</td>
<td>MEAG Power</td>
</tr>
<tr>
<td></td>
<td>Manager Regulatory Policy</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 3-2017-18</strong></td>
<td>John Bussman</td>
<td>Associated Electric Cooperative, Inc.</td>
</tr>
<tr>
<td></td>
<td>Manager, Reliability Compliance</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 4-2016-17</strong></td>
<td>Chris Gowder</td>
<td>Florida Municipal Power Agency</td>
</tr>
<tr>
<td></td>
<td>Regulatory Compliance Manager</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 4-2017-18</strong></td>
<td>Barry Lawson</td>
<td>National Rural Electric Cooperative Association</td>
</tr>
<tr>
<td></td>
<td>Associate Director, Power Delivery and Reliability</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 5-2016-17</strong></td>
<td>Randy Crissman</td>
<td>New York Power Authority</td>
</tr>
<tr>
<td></td>
<td>Vice President – Technical Compliance</td>
<td></td>
</tr>
<tr>
<td><strong>Segment 5-2017-18</strong></td>
<td>Amy Casuscelli</td>
<td>Xcel Energy</td>
</tr>
<tr>
<td></td>
<td>Sr. Reliability Standards Analyst</td>
<td></td>
</tr>
<tr>
<td>Segment</td>
<td>2016-17</td>
<td>2017-18</td>
</tr>
<tr>
<td>---------</td>
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</tr>
<tr>
<td>Segment 6</td>
<td>Andrew Gallo</td>
<td>Brenda Hampton</td>
</tr>
<tr>
<td></td>
<td>Director, Reliability Compliance</td>
<td>Regulatory Policy</td>
</tr>
<tr>
<td></td>
<td>City of Austin dba Austin Energy</td>
<td>Energy Future Holdings – Luminant Energy Company LLC</td>
</tr>
<tr>
<td>Segment 7</td>
<td>Frank McElvain</td>
<td>vacant</td>
</tr>
<tr>
<td></td>
<td>Senior Manager, Consulting</td>
<td></td>
</tr>
<tr>
<td>Segment 8</td>
<td>Robert Blohm,</td>
<td>David Kiguel</td>
</tr>
<tr>
<td></td>
<td>Managing Director</td>
<td>Independent</td>
</tr>
<tr>
<td>Segment 9</td>
<td>Alexander Vedvik</td>
<td>Michael Marchand</td>
</tr>
<tr>
<td></td>
<td>Senior Electrical Engineer</td>
<td>Senior Policy Analyst</td>
</tr>
<tr>
<td>Segment 10</td>
<td>Guy Zito</td>
<td>Steve Rueckert</td>
</tr>
<tr>
<td></td>
<td>Assistant Vice President of Standards</td>
<td>Director of Standards</td>
</tr>
<tr>
<td></td>
<td>Northeast Power Coordinating Council</td>
<td>Western Electricity Coordinating Council</td>
</tr>
</tbody>
</table>
## Parliamentary Procedures


### Motions

Unless noted otherwise, all procedures require a “second” to enable discussion.

<table>
<thead>
<tr>
<th>When you want to...</th>
<th>Procedure</th>
<th>Debatable</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Raise an issue for discussion</td>
<td>Move</td>
<td>Yes</td>
<td>The main action that begins a debate.</td>
</tr>
<tr>
<td>Revise a Motion currently under discussion</td>
<td>Amend</td>
<td>Yes</td>
<td>Takes precedence over discussion of main motion. Motions to amend an amendment are allowed, but not any further. The amendment must be germane to the main motion, and cannot reverse the intent of the main motion.</td>
</tr>
<tr>
<td>Reconsider a Motion already approved</td>
<td>Reconsider</td>
<td>Yes</td>
<td>Allowed only by member who voted on the prevailing side of the original motion.</td>
</tr>
<tr>
<td>End debate</td>
<td>Call for the Question or End Debate</td>
<td>No</td>
<td>If the Chair senses that the committee is ready to vote, he may say “if there are no objections, we will now vote on the Motion.” The vote is subject to a 2/3 majority approval. Also, any member may call the question. This motion is not debatable. The vote is subject to a 2/3 vote.</td>
</tr>
<tr>
<td>Record each member’s vote on a Motion</td>
<td>Request a Roll Call Vote</td>
<td>No</td>
<td>Takes precedence over main motion. No debate allowed, but the members must approve by 2/3 majority.</td>
</tr>
<tr>
<td>Postpone discussion until later in the meeting</td>
<td>Lay on the Table</td>
<td>Yes</td>
<td>Takes precedence over main motion. Used only to postpone discussion until later in the meeting.</td>
</tr>
<tr>
<td>Postpone discussion until a future date</td>
<td>Postpone until</td>
<td>Yes</td>
<td>Takes precedence over main motion. Debatable only regarding the date (and time) at which to bring the Motion back for further discussion.</td>
</tr>
<tr>
<td>Remove the motion for any further consideration</td>
<td>Postpone indefinitely</td>
<td>Yes</td>
<td>Takes precedence over main motion. Debate can extend to the discussion of the main motion. If approved, it effectively “kills” the motion. Useful for disposing of a badly chosen motion that can not be adopted or rejected without undesirable consequences.</td>
</tr>
<tr>
<td>Request a review of procedure</td>
<td>Point of order</td>
<td>No</td>
<td>Second not required. The Chair or secretary shall review the parliamentary procedure used during the discussion of the Motion.</td>
</tr>
</tbody>
</table>
Notes on Motions

Seconds. A Motion must have a second to ensure that at least two members wish to discuss the issue. The “seconder” is not recorded in the minutes. Neither are motions that do not receive a second.

Announcement by the Chair. The Chair should announce the Motion before debate begins. This ensures that the wording is understood by the membership. Once the Motion is announced and seconded, the Committee “owns” the motion, and must deal with it according to parliamentary procedure.
### Voting

<table>
<thead>
<tr>
<th>Voting Method</th>
<th>When Used</th>
<th>How Recorded in Minutes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unanimous Consent The standard practice.</td>
<td>When the Chair senses that the Committee is substantially in agreement, and the Motion needed little or no debate. No actual vote is taken.</td>
<td>The minutes show “by unanimous consent.”</td>
</tr>
<tr>
<td>Vote by Voice</td>
<td>The standard practice.</td>
<td>The minutes show Approved or Not Approved (or Failed).</td>
</tr>
<tr>
<td>Vote by Show of Hands (tally)</td>
<td>To record the number of votes on each side when an issue has engendered substantial debate or appears to be divisive. Also used when a Voice Vote is inconclusive. (The Chair should ask for a Vote by Show of Hands when requested by a member).</td>
<td>The minutes show both vote totals, and then Approved or Not Approved (or Failed).</td>
</tr>
<tr>
<td>Vote by Roll Call</td>
<td>To record each member’s vote. Each member is called upon by the Secretary, and the member indicates either “Yes,” “No,” or “Present” if abstaining.</td>
<td>The minutes will include the list of members, how each voted or abstained, and the vote totals. Those members for which a “Yes,” “No,” or “Present” is not shown are considered absent for the vote.</td>
</tr>
</tbody>
</table>

### Notes on Voting

(Recommendations from DMB, not necessarily Mr. Robert)

**Abstentions.** When a member abstains, he is not voting on the Motion, and his abstention is not counted in determining the results of the vote. The Chair should not ask for a tally of those who abstained.

**Determining the results.** The results of the vote (other than Unanimous Consent) are determined by dividing the votes in favor by the total votes cast. Abstentions are not counted in the vote and shall not be assumed to be on either side.

“**Unanimous Approval.**” Can only be determined by a Roll Call vote because the other methods do not determine whether every member attending the meeting was actually present when the vote was taken, or whether there were abstentions.

**Majorities.** Robert’s Rules use a simple majority (one more than half) as the default for most motions. NERC uses 2/3 majority for all motions.