Introduction and Chair's Remarks

NERC Antitrust Compliance Guidelines and Public Announcement*

Agenda Items

1. Review September 7 Agenda — (Approve) (B. Murphy) (1 minute)
2. Consent Agenda — (Approve) (B. Murphy) (1 minute)
   a. July 19, 2017 Standards Committee Meeting Minutes* — (Approve)
3. Standards Committee Chair and Vice Chair Election* — (Elect)
4. Upcoming Standards Projects or Issues — (Update)
   a. Three-Month Outlook* (S. Noess; B. Murphy) (10 minutes)
   b. Reliability Standards Efficiency Review (S. Noess) (10 minutes)
5. Projects Under Development — (Review)
   a. Project Tracking Spreadsheet (C. Yeung) (10 minutes)
   b. Projected Posting Schedule (S. Noess) (5 minutes)
6. 2018 Standards Committee Meeting Dates* — (Approve) (C. Larson) (5 minutes)
7. Project 2015-09 Establish and Communicate System Operating Limits* — (Authorize) (S. Kim) (10 minutes)
8. Project 2015-10 Single Points of Failure TPL-001-5* — (Authorize) (S. Kim) (10 minutes)
9. Project 2016-02 Modifications to CIP Standards CIP-002-6* — (Authorize) (S. Cavote) (10 minutes)
11. Request for Interpretation FAC-002-2*— (Reject) (S. Kim) (10 minutes)
12. 2018-2020 Reliability Standards Development Plan* — (Endorse) (S. Cavote) (10 minutes)

13. Technical Rationale* — (Endorse) (B. Murphy; S. Noess) (10 minutes)

14. Subcommittee Reports and Updates
   a. Project Management and Oversight Subcommittee — (Update) (C. Yeung) (5 minutes)
   b. Process Subcommittee* — (Update) (B. Li) (5 minutes)

15. Legal Update and Upcoming Standards Filings* — (Review) (S. Elstein) (5 minutes)

16. Informational Items — (Enclosed)
   a. 2018-2019 Standards Committee Member Elections*
   b. Standards Committee Expectations*
   c. 2017 Meeting Dates and Locations*
   d. 2017 Standards Committee Roster*
   e. Highlights of Parliamentary Procedure*

17. 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.
Minutes
Standards Committee Meeting
July 19, 2017 | 1:00 to 4:00 p.m. Eastern

M. D’Antuono, vice chair, called the meeting of the Standards Committee (SC or the Committee) to order on July 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
M. D’Antuono welcomed the Committee and guests. She noted the current Committee Chair and Vice Chair will not be seeking reelection later in 2017. M. D’Antuono also highlighted that the Cyber Security Supply Chain standard is within final ballot ending on July 20. She reminded members and observers of various meeting etiquette for the SC calls. S. Noess thanked both the chair and vice chair for all of their service and contributions over the last several years.

Review July 19, 2017 Agenda (agenda item 1)

Approved by unanimous consent the addition of agenda item 17, move Consent Agenda Item 2e to Agenda Item 12a, and a waiver of five-day rule considering an additional candidate for NUC-003-1 Periodic Review was added.

Consent Agenda (agenda item 2)

Motion to adopt June 14, 2017 Standards Committee Meeting Minutes
Approved by unanimous consent.

Motion to approve Standards Committee Chair and Vice Chair Election process
Approved by unanimous consent.

Motion to endorse Project Management and Oversight Subcommittee Vice Chair Selection
Approved by unanimous consent.

Motion to approve Errata for VAR-501-WECC-3.1
Approved by unanimous consent.

Motion to move BAL-002-2 and BAL-003-1.1 SAR Drafting Team solicitation agenda item 2e to agenda item 12a.
S. Bodkin made a motion to move Consent Agenda item 2e to Agenda Item 12a, which the Committee approved by unanimous consent.

Upcoming Standards Projects or Issues (agenda item 3)
Three-Month Outlook
S. Noess provided highlights of the Three-Month Outlook.

Projects Under Development (agenda item 4)
C. Yeung reviewed the Project Tracking Spreadsheet (Project Tracking Spreadsheet). He reiterated that the Cyber Security Supply Chain ballot closes July 20. He also noted the upcoming August 9-10 Board of Trustees meeting.

S. Noess reviewed the Projected Posting Schedule (Projected Posting Schedule). There were no comments or questions from the SC or observers.

2018 Standards Committee Meeting Dates (agenda item 5)
B. Li made a motion to accept the action item as written; G. Zito seconded. B. Li requested the meeting dates be made as a proposal to the SC in September or October, and allow SC members to weigh in on the dates selected. The motion was as follows:

Approve the formation of a small working team of Standards Committee Executive Committee members to coordinate with NERC staff in order to determine the number and locations of Standards Committee (SC) and subcommittee meetings and their respective dates.

The Committee approved the motion with no objections or abstentions.

Project 2016-02 Modifications to CIP Standards CIP-012-1 (agenda item 6)
S. Bodkin made a motion to accept the action item as written; B. Li seconded. The motion was as follows:

Authorize posting proposed Reliability Standard CIP-012-1, the associated Implementation Plan, Violation Risk Factors, and Violation Severity Levels for a 45-day formal comment period with parallel initial ballot and non-binding poll during the last 10 days of the comment period.

The Committee approved the motion with no objections or abstentions.

Project 2016-04 Modifications to PRC-025-1 (agenda item 7)
G. Zito made a motion to accept the action item as written; C. Gowder seconded. The motion was as follows:

Authorize the initial posting of draft Reliability Standard PRC-025-2 Generator Relay Loadability, its associated Implementation Plan, and Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) Justification for a formal 45-day comment period with ballot pool formation during the first
30 days. An initial ballot of the standard and a non-binding poll of the VRFs and VSLs to be held during the last 10 days of the comment period.

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

**Project 2017-03 FAC-008-3 Periodic Review (agenda item 8)**

G. Zito made a motion to accept the action item as written; S. Rueckert seconded. L. Lee raised a question about drafting team experience of the standard drafting team (SDT) chair and vice chair. S. Cavote said this was given consideration, yet their other qualifications were remarkable. The motion was as follows:

Appoint members, chair, and vice chair to the periodic review team (PRT) for Project 2017-03 FAC-008-3 Periodic Review, as recommended by NERC staff.

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

- William Winters, chair, Consolidated Edison Company of NY, Inc.
- Josephine Daggett, vice chair, Western Area Power Administration
- Kimberly M. Jursic, Georgia Power Company
- Mario L. Kiresich, Southern California Edison
- Hassib El Murdea, Ontario Power Generation
- Brett Riedl, ComEd
- Jeff Gruseck, Duke Energy
- Yaoyu Wang, American Electric Power Company

**Project 2017-04 Periodic Review of INT Standards (agenda item 9)**

S. Bodkin made a motion to accept the action item as written; B. Li seconded. The motion was as follows:

Appoint members, chair, and vice chair to the periodic review team (PRT) for Project 2017-04 Periodic Review, as recommended by NERC staff.

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

- Gary Nolan, chair, Arizona Public Service
- Robert Staton, vice chair, Public Service Company of Colorado (Xcel Energy)
- Richard Cobb, MISO
- Eric Henderson, Southwest Power Pool
• Jeffrey McLaughlin, PJM Interconnection, LLC
• Margaret Olczak, Bonneville Power Administration
• Kevin Tate, Southern Company
• Robert Witham, Western Area Power Administration

Project 2017-05 Periodic Review of NUC-001-3 (agenda item 10)
S. Rueckert made a motion to accept the action item as written; G. Zito seconded. S. Cavote acknowledged that S. Rueckert and WECC made an extra effort to recruit a seventh SDT member in order to round out the team. The late addition resulted in the waiver of the SC agenda five-day rule. The motion was as follows:

Appoint members, chair, and vice chair to the periodic review team (PRT) for Project 2017-05 NUC-001-3 Periodic Review, as recommended by NERC staff.

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

• Alison Mackellar, chair, Exelon Generation
• Mukund Chander, vice chair, Entergy
• Karie L. Barczak, DTE Electric Co.
• Nick Ware, ITC Holdings
• Kevin Clark, ISO New England
• Augustine Caven, PJM Interconnection
• Bobbi Welch, Arizona Public Service

Project 2017-07 Standards Alignment with Registration (agenda item 11)
G. Zito made a motion to accept the action item as written; S. Rueckert seconded. S. Cavote described the high level scope of the project, and specified that all standards would be reviewed for modifications in which the applicable entity may be removed. The motion was as follows:

Authorize posting the Standards Alignment with Registration Standard Authorization Request (SAR) for a 30-day formal comment period, posting the MOD-032-1 SAR for a 30-day formal comment period, and posting for nominations of a SAR drafting team to consider both and develop a combined final SAR.

The Committee approved the motion with no objections or abstentions.
Standard Authorization Request for BAL-003-1.1 (agenda item 12)
B. Hampton made an amended motion; S. Bodkin seconded. B. Lawson questioned whether the SC should be requesting additional technical documentation or requesting additional approaches. G. Zito recommended the technical document supplement also be sent to the Operating Committee (OC). C. Yeung asked if an informal posting would accomplish the same intent by gathering feedback from industry. SC members discussed the various options for approach, and heard comments from J. Rust, the submitter of the SAR, after the vote was taken. The motion was as follows:

Delay action on BAL-003-1.1 SAR, forward the SAR and Technical Document Supplement to the Operating Committee for technical review, and request the OC provide a recommended approach to address the issue(s) raised in the SAR.

The Committee approved the motion with 12 affirmative votes (L. Lee, S. Bodkin, B. Li, C. Yeung, J. Bussman, C. Gowder, S. Spagnolo, M. Flexter, A. Gallo, B. Hampton, D. Kiguel, and G. Zito), 2 Negative (S. Rueckert and F. McElvain), and 4 abstentions (J. Tarantino, R. Blohm, B. Lawson, and A. Vedvik).

BAL-002-2 & BAL-003-1.1 SAR Drafting Team nominations (agenda item 12a, originally item 2e)
S. Bodkin made a motion to accept the action item as written, B. Hampton seconded. S. Noess and S. Kim noted previous nominations will still be considered.

Authorize posting for solicitation of additional nominees for Standard Authorization Request (SAR) drafting team members for Project 2017-01 BAL-003-1.1 and Project 2017-06 BAL-002-2 for a 14-day period.

The Committee approved the motion with no objections or abstentions.

Request for Interpretation and Standard Authorization Request PRC-024 (agenda item 13)
G. Zito made a motion to accept the action item as written with a friendly amendment annotated underlined below; S. Rueckert seconded. G. Zito shared that there is an industry concern on the clarity of this standard as demonstrated by the SAR and RFI, and recommended the standard is reviewed in 2018. B. Lawson raised a concern about this being addressed within Implementation Guidance as compared to an RFI. The motion was as follows:

Reject both the Request for Interpretation (RFI) and Standard Authorization Request (SAR) of PRC-024-2 submitted by Nuclear Energy Institute-NERC Issues Task Force (NEI-NITF), and provide a written explanation to the submitter within 10 days of the decision. In addition, PRC-024-3 will be added to the list of standards eligible for standards grading in 2018.

The Committee approved the motion with B. Lawson objecting and D. Kiguel abstaining.
Standard Authorization Request of INT-004-3.1 (agenda item 14)
S. Bodkin made a motion to accept the action item as written; G. Zito seconded. An erratum change was made for the title of agenda item 14 on page 2 of the Agenda, clarifying this is a Standard Authorization Request and not a Request for Interpretation. The title on the documentation in the agenda package was correct. The motion was as follows:

Reject the Standard Authorization Request (SAR) of INT-004-3.1 submitted by Gridforce Energy Management, L.L.C (Gridforce), and provide a written explanation to the submitter within 10 business days of the decision.

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

Request for Interpretation of PRC-024 (agenda item 15)
B. Lawson made a motion to accept the action item as written; B. Hampton seconded. B. Lawson requested more detail on where this is stated in the development process, and questioned whether or not RFI rejection can be used as part of an audit record. The motion was as follows:

Reject the Request for Interpretation (RFI) of PRC-024-2 submitted by California Independent System Operator (ISO), and provide a written explanation to the submitter within 10 business days of the decision.

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

Standard Authorization Request for CIP-014-3 (agenda item 16)
S. Bodkin made an amended motion; J. Bussman seconded. SC members discussed whether the SAR raised an issue with compliance implementation guidance or with the implementation plan of the Reliability Standard. SC members discussed various merits of the original motion and amended motion. The motion was as follows:

Reject the CIP-014-3 SAR for good cause, in accordance with Section 4.1 of SPM, on the grounds the SAR raises a question regarding compliance implementation guidance and does not request a new or modified Reliability Standard.

*The Committee approved the amended motion with 10 affirmative votes from S. Bodkin, B. Li, C. Yeung, J. Bussman, D. Kiguel, M. Flexter, A. Gallo, F. McElvain, R. Blohm, and A. Vedvik. Objecting were L. Lee, J. Tarantino, C. Gowder, B. Lawson, S. Spagnolo, G. Zito, and S. Rueckert. Abstaining was B. Hampton.*
SDT Drafting Implementation Guidance (agenda item 17 modified)
S. Bodkin raised a question about whether or not standard drafting teams are eligible to develop implementation guidance during the standards drafting process. S. Noess confirmed that SDTs are eligible to develop implementation guidance. B. Lawson requested that this be clarified with the Modifications to CIP Standards team and reflected in the SC minutes.

Subcommittee Reports and Updates (agenda item 18)

Project Management and Oversight Subcommittee
C. Yeung provided an update of Project Management and Oversight Subcommittee (PMOS) activities.

Process Subcommittee
B. Li provided an update of Standards Committee Process Subcommittee work activities. He said the Standard Processes Manual working team will be meeting August 1 to review comments and future revisions.

Legal Update (agenda item 19)
L. Perotti provided her update regarding recent and upcoming standards filings.

Informational Items (agenda item 20)
No discussion on informational items.

Adjourn
M. D’Antuono thanked the Committee members and observers, and adjourned the meeting at 4:00 p.m. Eastern.
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<th>Proxy</th>
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<td>NextEra Energy, Inc.</td>
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<td>Vice-Chair 2016-17</td>
<td>Michelle D’Antuono</td>
<td>Occidental Energy Ventures, LLC</td>
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<td>Laura Lee</td>
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<td>Andrew Gallo</td>
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<td>Brenda Hampton</td>
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<td>Frank McElvain</td>
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<td>Michael Marchand</td>
<td>Arkansas Public Service Commission</td>
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<td>Guy Zito</td>
<td>Northeast Power Coordinating Council</td>
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Standards Committee Chair and Vice Chair Election

Action
Elect a Standards Committee (SC) Chair and Vice Chair for the 2018-2019 term.

Background
In accordance with the attached Process for Election of Chair and Vice Chair approved at the SC’s July 19, 2017 meeting, a nomination period was held from July 20, 2017 through August 21, 2017. The SC nomination committee, consisting of Randy Crissman, Guy Zito, and Sean Bodkin, received one nomination for Chair, Andrew Gallo. No nominations were received for Vice Chair. The term, duties, and responsibilities of the elected Chair and Vice Chair start on January 1, 2018 and end on December 31, 2019.

As specified at the July 19, 2017 meeting, the following process will be used:

1. At the September 7, 2017 SC face-to-face meeting, elections for the chair and vice chair will be conducted immediately after the consent agenda is completed. The elections shall be accomplished as follows:
   a. The nominating committee will ask if there are any nominations from the floor. If there is a nomination from the floor, the nominee shall be provided five minutes to orally present his or her qualifications to the SC.

   b. After (a) is completed, the secretary of the SC shall distribute written election ballots for both chair and vice chair. The members shall mark their selection on the ballot and provide the ballot back to the secretary. Any SC member participating by phone shall submit his or her selections to the Secretary via email. The chair and vice chair have the right to vote in both of the elections for Chair and Vice Chair.

2. After all written and email ballots are collected by the secretary, the secretary and members of the nominating committee shall leave the room and together count the ballots. After the secretary and nominating committee members agree to the vote count, they shall re-enter the room and announce the vote count totals. If for any reason a majority of votes was not received by a nominee for Chair or Vice Chair, the nominee with the lowest vote count shall be dropped from the ballot and a second ballot shall be produced and a second election conducted, using the same process as used for the first ballot. This process of eliminating the lowest vote count from the nomination list shall be used until a majority vote is obtained for Chair and Vice Chair, as needed. (Note: the intention of the election process is to allow for confidentiality of the voters, while providing the transparency of the final vote count. Thus, the secretary of the SC and the nominating committee shall not disclose any names of who voted for who (which may have been ascertained from email ballots or otherwise) during or after the election.)
Three-Month Outlook

Brian Murphy, SC Chair, NextEra Energy Resources, LLC
Steven Noess, Director of Standards Development, NERC
Standards Committee
August 28, 2017
Authorize Nomination Solicitations

- September
  - None
- October
  - None
- November
  - None
Authorize Team Appointments

- September
  - None

- October
  - Project 2017-01 Modifications to BAL-003-1.1
  - Project 2017-06 Modifications to BAL-002-2

- November
  - None
Authorize SAR Postings

- September
  - None
- October
  - None
- November
  - None
• September
  ▪ Project 2015-09 Establish and Communicate System Operating Limits (FAC-010, FAC-011, FAC-014)
  ▪ Project 2015-10 Single Points of Failure (TPL-001-5)
  ▪ Project 2016-02 Modifications to CIP Standards (CIP-002-6) TOCC

• October
  ▪ None

• November
  ▪ None
FERC Orders and NOPRs

- July
  - None
- August
  - None
- September
  - None
Questions and Answers
2018 Standards Committee Meeting Dates

Action
Approve recommended dates and locations for Standards Committee (SC) and subcommittee meetings.

Background
The Standards Committee Executive Committee (SCEC) at-large members working in conjunction with NERC staff developed a preliminary list of dates, times, and locations of in-person meetings and conference calls for the 2018 calendar year, while taking into consideration NERC Board of Trustees dates, holidays, and travel costs.

SC in-person meetings will be held quarterly covering project items, subcommittee updates, and a Three-month outlook. SC meeting times are scheduled from 10:00 a.m. – 3:00 p.m. local. Standard Committee Process Subcommittee meeting would be held the afternoon prior, typically from 1:00 – 4:00 p.m. local, while the Project Management and Oversight Subcommittee meeting would be held the same day prior to the scheduled SC meeting.

- March 14, 2018: Salt Lake City, UT (WECC)
- June 13, 2018: Atlanta, GA (NERC)
- September 12, 2018: Sacramento, CA (SMUD)
- December 12, 2018: Atlanta, GA (NERC)

SC conference calls will be scheduled each month in between the in-person meetings. All conference call times are 1:00 – 3:00 p.m. Eastern. Agenda topics will generally be limited to only those items for which an SC action is required, if any (for example, acting to approve posting for initial ballot, acting on Requests for Interpretation or Standard Authorization Requests (SAR), authorizing solicitations to seek drafting team members, seating SAR drafting teams or standard drafting teams, endorsements, etc.) Informational items such as the Three-month outlook, project tracking spreadsheet, subcommittee reports, etc., will only occur during the quarterly in-person meetings. In this manner, if there is no action for the SC to take in a given month, the meeting may not be necessary. The chair, vice chair, and secretary could cancel the call at their discretion. The number of scheduled conference calls was increased, compared to 2017, from four to eight, in order to avoid the need to schedule special calls. Standard Committee Process Subcommittee and Project Management and Oversight Subcommittee would set their respective meeting dates once SC meeting dates are finalized.

- January 17, 2018
- February 14, 2018 (Board of Trustees (Board): February 7-8)
- April 18, 2018
- May 16, 2018 (Board: May 15-16)
- July 18, 2018
- August 22, 2018 (Board: August 15-16)
- October 17, 2018
- November 14, 2018 (Board: November 6-7)
Project 2015-09 Establish and Communicate System Operating Limits

**Action**
Authorize initial posting of the following Project 2015-09 Establish and Communicate System Operating Limits documents for a 45-day formal comment period with parallel initial ballots and non-binding polls on the Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) conducted during the last 10 days of the comment period:

- Reliability Standard FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits
- Reliability Standard FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology
- Definition of System Voltage Limit (SVL) for inclusion in the Glossary of Terms Used in NERC Reliability Standards (“NERC Glossary”)
- Implementation Plan associated with all of the above

**Background**
Facilities Design, Connections, and Maintenance (FAC) standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES). Project 2015-09 is revising the requirements for determining and communicating these SOLs and addressing the issues identified in Project 2015-03 Periodic Review of System Operating Limit Standards (FAC-010-3, FAC-011-3, and FAC-014-2). The recommendations of the Periodic Review Team included:

- Propose retirement of FAC-010-3 (BES planning is covered under approved TPL-001-4 which provides comprehensive requirements for a variety of contingencies.)
- Clarify acceptable System performance criteria for the operations time horizon.
- Address the Federal Energy Regulatory Commission Order No. 777 directive for the communication of Interconnection Reliability Operating Limit (IROL) information to Transmission Owners.
- Clarify responsibilities for establishing and communicating SOLs (propose requirements to clearly delineate the functional entity responsibilities for determining and communicating each type of SOL (Facility Ratings, System voltage limits, voltage stability limits, and transient stability limits) where not already addressed in existing standards (e.g., FAC-008).
- Develop requirement(s) that facilitate transfer of necessary reliability information between the planning and operating entities for establishing and communicating SOLs.
The revisions eliminate the overlap with approved Transmission Planning (TPL) requirements, enhance consistency with Transmission Operations (TOP) and Interconnection Reliability Operations (IRO) standards, and address issues with determining and communicating SOLs and IROLs.

Concurrently, the drafting team is posting revisions to the definition of SOL and the definition of a new term, SOL Exceedance, to be incorporated into the NERC Glossary for a 30-day informal comment period. The revised and new definitions are proposed to provide clarity and alignment with how SOLs are treated in the TOP and IRO standards. These definitions are intended to promote a common understanding of what it means to establish and exceed SOLs.

The Quality Review for this posting was performed August 9, 2017 through August 14, 2017. Participants of Quality Review included Darrel Richardson, Al McMeekin, Soo Jin Kim (NERC Standards), Shamai Elstein (NERC Legal), Ken Lanehome (BPA and PMOS representative), Guy Zito (NPCC), and Vic Howell (standard drafting team (SDT) leadership). The reviewed documents were presented to the full SDT for consideration. Vic Howell, chair of the SDT, approved the final documents that were submitted to the SC for authorization to post for a 45-day comment/ballot period. There were no deviations from the Standard Processes Manual.
Standard Development Timeline

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

Description of Current Draft

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<td>January 2018 through February 2018</td>
</tr>
<tr>
<td>10-day final ballot</td>
<td>February 2018</td>
</tr>
<tr>
<td>NERC Board (Board) adoption</td>
<td>May 2018</td>
</tr>
</tbody>
</table>
A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon
2. **Number:** FAC-011-4
3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. **Applicability:**
   
   4.1. **Functional Entities:**
   
   4.1.1. Reliability Coordinator

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

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs (SOL Methodology) within its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

   3.1. Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator’s SOL Methodology;

   3.2. Require that System Voltage Limits respect the Facility voltage Ratings;
3.3. Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;

3.7. Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability;

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.
4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions\(^1\).

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: \textit{[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]}

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:
- generator;
- transmission circuit;
- transformer;
- shunt device;
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: \textit{[Violation Risk Factor: High] [Time Horizon: Operations Planning]}

6.1. A description of how to identify the subset of SOLs that qualify as IROLs.

\(^1\) The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits.
6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_v.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to:
[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;

8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

M8. Acceptable evidence that the RC provided its SOL Methodology to the entities identified in Requirement R8 may include, but is not limited to, dated electronic or hard copy documentation such as emails with receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Reliability Coordinator shall keep data or evidence of compliance with Requirements R1 through R8 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

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

<table>
<thead>
<tr>
<th>R #</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>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not have a methodology for establishing SOLs (“SOL Methodology”) within its Reliability Coordinator Area.</td>
</tr>
<tr>
<td>R2.</td>
<td>N/A</td>
<td>N/A</td>
<td></td>
<td>The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.</td>
</tr>
<tr>
<td>R3.</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into the SOL Methodology.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Failure Description</td>
<td>Failure Description</td>
<td>Failure Description</td>
<td>Failure Description</td>
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<tr>
<td>-------------</td>
<td>---------------------</td>
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</tr>
<tr>
<td>R4.</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into the SOL Methodology.</td>
</tr>
<tr>
<td>R5.</td>
<td>N/A</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into the SOL Methodology.</td>
<td>The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into the SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.3, 5.3, and 5.4 of Requirement R5 into the SOL Methodology.</td>
</tr>
<tr>
<td>R6.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not include a description of how to identify the subset of SOLs that qualify as IROLs. OR The Reliability Coordinator did not include a criteria for determining when violating a SOL qualifies as an IROL.</td>
<td>The Reliability Coordinator did not include a description of how to identify the subset of SOLs that qualify as IROLs AND The Reliability Coordinator did not include a criteria for determining when violating a SOL qualifies as an IROL.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Interconnection Reliability Operating Limit (IROL). OR The Reliability Coordinator did not include criteria for developing any associated IROL $T_v$.</td>
<td>Interconnection Reliability Operating Limit (IROL) AND The Reliability Coordinator did not include a criteria for developing any associated IROL $T_v$.</td>
<td></td>
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<tr>
<td>R7.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established. The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.</td>
<td></td>
</tr>
</tbody>
</table>
| R8. | The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4 but was late by less than or equal to 10 calendar days. | The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days. | The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Requirement R8, Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days. The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Requirement R8, Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Requirement R8, Parts 8.1 through 8.3 prior to
8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days. The effective date of the SOL Methodology.

OR
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4, but was late by more than 30 calendar days.

OR
The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4.

<table>
<thead>
<tr>
<th>D. Regional Variances</th>
<th>None.</th>
</tr>
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<tbody>
<tr>
<td>E. Interpretations</td>
<td>None</td>
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<tr>
<td>F. Associated Documents</td>
<td>Implementation Plan</td>
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</tbody>
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## Version History

<table>
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<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>New</td>
</tr>
<tr>
<td>2</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) pending applicable regulatory approval.</td>
<td>Revised</td>
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<tr>
<td>2</td>
<td>November 13, 2014</td>
<td>Adopted by the NERC Board of Trustees</td>
<td></td>
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<tr>
<td>3</td>
<td>November 19, 2015</td>
<td>FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.</td>
<td>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</td>
</tr>
<tr>
<td>4</td>
<td>Project 2015-09 Adopt revised standard.</td>
<td>Revision</td>
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A. Introduction

1. Title: System Operating Limits Methodology for the Operations Horizon

2. Number: FAC-011-3

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability:

4.1. Functional Entities:

4.1.1. Reliability Coordinator

5. Effective Date: See associated Implementation Plan for FAC-011-3.

B. Requirements and Measures

The

R1. Each Reliability Coordinator shall have a documented methodology for use in establishing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Be applicable for developing SOLs used in the operations horizon.

1.2. State that SOLs shall not exceed associated Facility Ratings.

M1. Include a description of how to identify the subset of SOLs that qualify. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
1.3. Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as iROLS.

1.4.3.1. The specified in the Reliability Coordinator’s SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Require the use of common System Voltage Limits between the Reliability Coordinator’s Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;

3.7. Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R3.

R2.R4. Each Reliability Coordinator shall include a requirement that SOLs provide BES performance consistent with the following in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. In the pre-contingency Specify stability performance criteria, including any margins applied. The criteria shall include the following:

4.1.1. steady state, the BES shall demonstrate voltage stability;

4.1.2. transient, dynamic and voltage response;

4.1.3. angular stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage

4.1.4. System damping.

4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

2.4.4.4. Describe how instability risks are identified, considering levels of transfers, Load and stability limits. In the determination of SOLs, the BES condition used
shall reflect current or expected system generation dispatch, and System conditions including any changes to system topology such as Facility outages.

2.2. Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.

4.5. Single line to Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

Violation Risk Factor: Medium
Time Horizon: Operations Planning

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following, either by single phase to ground or a three phase Fault (whichever is more severe), with Normal Clearing, on any Faulted-normal clearing, or without a Fault:

- generator, line;
- transmission circuit;
- transformer, AC;
- shunt device.

2.2.1. Loss of any generator, line, transformer, or shunt device without a Fault.

Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

---

1 The Contingencies identified in FAC-011 R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

2 The planned use of under-frequency load-shedding (UFLS) is not allowed in the establishment of stability limits.
5.2. In determining the system's response to any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

2.3.5.4. The method for considering the Contingency events provided by the following shall be acceptable: Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

2.3.1. Planned or controlled interruption of electric supply Acceptable evidence may include, but is not limited to radial customers or some local network customers connected to, dated electronic or supplied by the Faulted Facility or by the affected area.

2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies.

2.3.3. System reconfiguration through manual or automatic control or protection actions.

2.4. To prepare for the next Contingency, system adjustments may be made, including changes to generation, use hard copy documentation of the transmission system, and the transmission system topology.

M1.M5. The Reliability Coordinator's SOL Methodology shall address all of that addresses the items listed in Requirement 1 through Requirement 3R5.

R3.R6. The Each Reliability Coordinator's methodology for determining SOLs Coordinator shall include, as a minimum, a description of the following, along with any reliability margins applied for each in its SOL Methodology: [Violation Risk Factor]: High [Time Horizon]: Operations Planning

3.1. Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)

3.2. Selection A description of applicable Contingencies

3.3. A process for determining which how to identify the subset of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions.

3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.
3.4.6.1. Level of detail of system models used to determine SOLs that qualify as IROLs.

3.5. Allowed uses of Remedial Action Schemes.

3.6. Anticipated transmission system configuration, generation dispatch and load level.

3.7.6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T.

M2.M6. The Reliability Coordinator’s Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology shall address all of those addresses the items listed in Requirement 1 through Requirement 3R6.

R4.R7. Each Reliability Coordinator shall issue in its SOL Methodology the method and any changes to that methodology prior to the effectiveness of the Methodology or of a change period for Transmission Operators to communicate SOLs it established to the Methodology, to all of the following its RC(s). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of the SOL Methodology that addresses the items listed in Requirement R7.

R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

4.1.8.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology within its Interconnection prior to the effective date of the SOL Methodology;

4.2.8.2. Each Planning Authority Coordinator and Transmission Planner that models responsible for planning any portion of the Reliability Coordinator’s Reliability Coordinator Area prior to the effective date of the SOL Methodology;

4.3.8.3. Each Transmission Operator that operates in the within its Reliability Coordinator Area. prior to the effective date of the SOL Methodology;

8.4. Each requesting Reliability Coordinator shall have that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

M3.M8. Acceptable evidence it issued that the RC provided its SOL Methodology, and any changes to that methodology, including the date they were issued, in accordance with the entities identified in Requirement 4.R8 may include, but is not limited to, dated
C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:

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

1.2. Evidence Retention:

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

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

- The [applicable entity(ies)] Reliability Coordinator shall keep data or evidence of Requirement X compliance with Requirements R1 through R8 for the current year plus the previous 12 calendar days/months/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.

1.3.1. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.3.1.1. SOL Methodology.
1.1.2 Superseded portions of its SOL Methodology that had been made within the past 12 months.
1.1.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exist:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

2.2. Level 2: The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4 through R3.7 and E1.

2.3. Level 3: There shall be a level three non-compliance if any of the following conditions exist:

2.3.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.3.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.3.3 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

3. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</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>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not have a methodology for establishing SOLs (&quot;SOL Methodology&quot;) within its Reliability Coordinator Area.</td>
</tr>
<tr>
<td>R2.</td>
<td>Not applicable, N/A</td>
<td>The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2, N/A, R1.3, OR The Reliability Coordinator has no documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area.</td>
<td>The Reliability Coordinator has a documented SOL Methodology, the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use in developing SOLs within operations. OR The Reliability Coordinator has a documented method, included in its SOL Methodology, the method for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.3.</td>
<td>The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1, Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.</td>
</tr>
</tbody>
</table>

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<table>
<thead>
<tr>
<th>Requirement</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>R2R3</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into the SOL Methodology, which requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state (R2.1).</td>
</tr>
<tr>
<td>R2R3</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into the SOL Methodology.</td>
</tr>
<tr>
<td>R2R3</td>
<td>The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into the SOL Methodology.</td>
</tr>
<tr>
<td>R2R3</td>
<td>The Reliability Coordinator’s SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4) The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into the SOL Methodology.</td>
</tr>
<tr>
<td>R3R4</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into the SOL Methodology, which includes a description for all but one of the following: R3.1 through R3.7.</td>
</tr>
<tr>
<td>R3R4</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into the SOL Methodology, which includes a description for all but two of the following: R3.1 through R3.7.</td>
</tr>
<tr>
<td>R3R4</td>
<td>The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into the SOL Methodology, which includes a description for all but three of the following: R3.1 through R3.7.</td>
</tr>
<tr>
<td>R3R4</td>
<td>The Reliability Coordinator’s SOL Methodology is missing a description of the following: R3.1 through R3.7. The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into the SOL Methodology.</td>
</tr>
<tr>
<td>R5</td>
<td>N/A</td>
</tr>
<tr>
<td>R5</td>
<td>The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into the SOL Methodology.</td>
</tr>
<tr>
<td>R5</td>
<td>The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into the SOL Methodology.</td>
</tr>
<tr>
<td>R5</td>
<td>The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into the SOL Methodology. OR</td>
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<tr>
<td>R6.</td>
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<tr>
<td>R7.</td>
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</table>
| **R8.** | The Reliability Coordinator failed to issue / provided its new or revised SOL Methodology and/or one or more changes to that methodology to one of the required entities specified to a requesting Reliability Coordinator in R4.1, R4.2, and R4.3, in accordance with Requirement R8, Part 8.4, OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was provided to all the required entities no later than or equal to 10 calendar days after the effectiveness of the change, | The Reliability Coordinator failed to issue / provided its new or revised SOL Methodology and/or one or more changes to that methodology to two of the required entities specified to a requesting Reliability Coordinator in R4.1, R4.2, and R4.3, OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was late by more than 10 calendar days after the effectiveness of the change, but less than or equal to 20 calendar days after the effectiveness of the change, | The Reliability Coordinator failed to issue / provided its new or revised SOL Methodology and/or one or more changes to that methodology to three of the required entities specified in R4 Requirement R8, Parts 8.1, R4.2, and R4 through 8.3, OR For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change, but was late by more than 20 calendar days after the effectiveness of the change, but less than or equal to 30 calendar days after the effective date of the SOL Methodology, OR The Reliability Coordinator provided its new or revised SOL Methodology to one or more of the required entities more than 30 parties specified in Requirement R8, Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology, | The Reliability Coordinator failed to issue / provided its new or revised SOL Methodology and/or one or more changes to that methodology to four or more of the required entities specified in R4 Requirement R8, Parts 8.1, R4.2, and R4 through 8.3, | The Reliability Coordinator provided its new or revised SOL Methodology to one or more of the required entities more than 30 parties specified in Requirement R8, Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology, | \[\text{communicate SOLs the Transmission Operator established.} \]
| established or the periodicity of SOL communication. |
The following Regional Difference shall be applicable in the Western Interconnection:

4.1. As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

4.1.1. Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

4.1.2. A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

OR

The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Requirement R8, Part 8.4.
4.1.3—Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

4.1.4—The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

4.1.5—A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

4.1.6—A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

4.1.7—The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

4.2—SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

4.2.1—All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

4.2.2—Cascading does not occur.

4.2.3—Uncontrolled separation of the system does not occur.

4.2.4—The system demonstrates transient, dynamic and voltage stability.

4.2.5—Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.

4.2.6— Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.

4.2.7—To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.
4.3. SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:

4.3.1. Cascading does not occur.

The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.

E. Interpretations

None

E.F. Associated Documents

Link to the Implementation Plan and other important associated documents.
### 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>November 1, 2006</td>
<td>Adopted by Board of Trustees</td>
<td>New</td>
</tr>
<tr>
<td>2</td>
<td>June 24, 2008</td>
<td>Adopted by Board of Trustees: FERC Order 705</td>
<td>Revised</td>
</tr>
<tr>
<td>2</td>
<td>January 22, 2010</td>
<td>Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order</td>
<td>Update</td>
</tr>
<tr>
<td>2</td>
<td>February 7, 2013</td>
<td>R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.</td>
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<tr>
<td>2</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>
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<tr>
<td>2</td>
<td>February 24, 2014</td>
<td>Updated VSLs based on June 24, 2013 approval.</td>
<td></td>
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<tr>
<td>3</td>
<td>November 13, 2014</td>
<td>Adopted by the NERC Board of Trustees</td>
<td>Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS</td>
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<tr>
<td>4</td>
<td>Project 2015-09 Adopt revised standard.</td>
<td>Revision</td>
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</table>
Standard Development Timeline

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

Description of Current Draft

<table>
<thead>
<tr>
<th>Completed Actions</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standards Committee approved Standard Authorization Request (SAR) for posting</td>
<td>08/19/15</td>
</tr>
<tr>
<td>SAR posted for comment</td>
<td>08/20/15 – 09/21/15</td>
</tr>
<tr>
<td>Draft Reliability Standard posted for Informal Comment Period</td>
<td>07/14/16 – 08/12/16</td>
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<table>
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<tr>
<th>Anticipated Actions</th>
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</thead>
<tbody>
<tr>
<td>45-day formal comment period with ballot</td>
<td>September 2017 through October 2017</td>
</tr>
<tr>
<td>45-day formal comment period with additional ballot</td>
<td>January 2018 through February 2018</td>
</tr>
<tr>
<td>10-day final ballot</td>
<td>February 2018</td>
</tr>
<tr>
<td>NERC Board (Board) adoption</td>
<td>May 2018</td>
</tr>
</tbody>
</table>
A. Introduction

1. Title: Establish and Communicate System Operating Limits
2. Number: FAC-014-3
3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.
4. Applicability:
   4.1. Functional Entities:
      4.1.1. Reliability Coordinator
      4.1.2. Transmission Operator
5. Effective Date: See associated Implementation Plan.

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). [Violation Risk Factor: High] [Time Horizon: Operations Planning]

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established IROLs in accordance with it SOL Methodology.

R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL Methodology. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator’s SOL Methodology. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability
Establish and Communicate System Operating Limits

Coordinator Area in accordance with its SOL Methodology. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL Tv for any IROL;

5.2.4. The associated Contingency(ies); and

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the information in accordance with Requirement R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of
Facilities owned by that entity that are critical to the derivation of the IROL. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

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

<table>
<thead>
<tr>
<th></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>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.</td>
</tr>
<tr>
<td>R2</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator’s SOL Methodology.</td>
</tr>
<tr>
<td>R3</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information</td>
<td>The Transmission Operator did not provide its SOLs to its Reliability Coordinator.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Description</td>
<td>Explanation</td>
<td></td>
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<tr>
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<tr>
<td>R4.</td>
<td></td>
<td>The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.</td>
<td></td>
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<td>R5.</td>
<td>The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide four or more of the items listed in Requirement R5 Parts 5.1 through 5.5.</td>
<td>The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5. The Reliability Coordinator did not provide four or more of the items listed in Requirement R5 Parts 5.1 through 5.5.</td>
<td></td>
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</tr>
<tr>
<td>R6.</td>
<td></td>
<td>The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.</td>
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D. Regional Variances
   None

E. Interpretations
   None

F. Associated Documents
   Implementation Plan
## Version History

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<td>Replaced Levels of Non-compliance with Violation Severity Levels</td>
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<td>Update</td>
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| 2       | April 29, 2015 – July 23, 2015 | Incorrectly included TOP as the applicable function for Requirement R5.  
7/23/15: Corrected to designate R5 as: RC, PA and TP. | Revised         |
| 3       |                    | Project 2015-09 Adopt revised standard.                               | Revision        |
Standard Development Timeline

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<tr>
<td>Draft Reliability Standard posted for Informal Comment Period</td>
<td>07/14/16 – 08/12/16</td>
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A. Introduction

1. Title: Establish and Communicate System Operating Limits

2. Number: FAC-014-2

3. Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. Applicability:

   5.1.1. Functional Entities:
   
   4.1.1. Reliability Coordinator
   5.1.1. Planning Authority
   5.1.2. Transmission Planner
   4.1.2. Transmission Operator

6. Effective Date: See associated Implementation Plan for FAC-014-2.

B. Requirements and Measures

R1. The each Reliability Coordinator shall ensure that SOLs, including establish Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with in accordance with its System Operating Limit Methodology (SOL Methodology). [Violation Risk Factor: High] [Time Horizon: Operations Planning]

M1. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that it developed its SOLs (including the subset of SOLs that are Reliability Coordinator established IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

R2. The each Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area that are consistent in accordance with its Reliability Coordinator’s SOL Methodology. [Violation Risk Factor: Medium] [Time Horizon: ]

R3. The Reliability Coordinator, Operations Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.
R4. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. [Violation Risk Factor:] [Time Horizon:]

M2. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

R5. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority’s SOL Methodology. [Violation Risk Factor:] [Time Horizon:]

M3. The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each be able to demonstrate that it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.

R6. The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: [Violation Risk Factor:] [Time Horizon:]

6.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator’s SOL Methodology. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator provided its SOLs in accordance with its Reliability Coordinator’s SOL Methodology.

R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

6.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL;

6.1.2.5.2.2. The value of the stability limit or IROL and its associated Tᵥ;

5.2.3. The associated IROL Tᵥ for any IROL;

6.1.3.5.2.4. The associated Contingency(ies); and

6.1.4.5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. The each impacted Transmission Operator shall provide any SOLs it developed within its Reliability Coordinator Area, the value of the stability limits established pursuant to its Reliability Coordinator Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Service Providers that share its portion of the Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

6.2.5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator’s Operational Planning Analyses.

6.3. The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to each requesting Transmission Planners, Transmission Service Providers, Transmission Operators and Operator within its Reliability Coordinators that work within its Planning Authority Coordinator Area.

6.4.5.5. The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, requested SOL information for its Reliability Coordinators, Transmission Operators, and Transmission Service
Providers that work within its Transmission Planning Coordinator Area and to adjacent Transmission Planners, on a mutually agreed upon schedule.

M4.M5. The Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied provided the information in accordance with schedules supplied by the requesters of such SOLs as specified in Requirement 5R5.

R7.R6. The Planning Authority shall identify the subset of multiple contingencies (if any), from Each Reliability Standard TPL-003 which result in stability limits. Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

7.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.

7.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator.

M5.M6. The Planning Authority shall have evidence it identified a provided the list of multiple contingencies (if any) and their associated stability limits and provided the list and the limits to its Reliability Coordinators Facilities in accordance with Requirement 6R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar days/months/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.

1.1. **Additional Compliance Information**

The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:

1.1.1—SOL Methodology(ies)

1.1.2—SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information

1.1.3—Evidence that SOLs were distributed

1.1.4—Evidence that a list of stability-related multiple contingencies and their associated limits were distributed

2. Distribution schedules provided by entities that requested SO
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>R1.</strong></td>
<td>There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1) N/A</td>
<td>There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1) N/A</td>
<td>There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R1) N/A</td>
<td>There are SOLs, the Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLS) for the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent in accordance with the Reliability Coordinator’s SOL Methodology (“SOL Methodology”) as established in FAC-011-4.</td>
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<tr>
<td><strong>R2.</strong></td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2) N/A</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2) N/A</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator’s SOL Methodology. (R2) N/A</td>
<td>The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 75% or more of these SOLs are inconsistent in accordance with the Reliability Coordinator’s SOL Methodology. (R2)</td>
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<tr>
<td><strong>R3.</strong></td>
<td>There are SOLs, for the Planning Coordinator Area,</td>
<td>There are SOLs, for the Planning Coordinator Area,</td>
<td>There are SOLs, the Transmission Operator provided its SOLs</td>
<td>There are SOLs, for the Planning Coordinator Area,</td>
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</table>
but from 1% up to, but less than, 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3) N/A

| R4. | The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4) N/A | The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4) N/A | The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4) N/A |
| R5. | The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are) One of the following: The responsible entity provided its SOLs (including the subset of SOLs that are) One of the following: The responsible entity failed to provide its SOLs (including the subset of SOLs that are) |

but 25% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3) N/A

but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3) N/A

but 75% or more of these SOLs are inconsistent with the Planning Coordinator’s SOL Methodology. (R3) The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3) The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
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<tr>
<th>R5.</th>
<th>The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.</th>
<th>IROLs) to all but one of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days... (R5) Or The supporting information provided with the IROLs does not address 5.1.4. The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.</th>
<th>IROLs) to all but two of the requesting entities within the schedules provided. (R5) Or The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days... (R5) Or The supporting information provided with the IROLs does not address 5.1.3. The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.</th>
<th>IROLs) to more than two of the requesting entities within 45 calendar days of the associated schedules. (R5) Or The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2. The Reliability Coordinator did not provide four or more of the items listed in Requirement R5 Parts 5.1 through 5.5.</th>
</tr>
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| R6. | The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2 N/A | Not applicable N/A | The Planning Authority identified the subset of multiple contingencies which result in stability limits but did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1) | The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6) Or The Planning Authority identified the subset of multiple contingencies which result in stability limits but did not provide the list of
D. Regional Variances

None.

E. Interpretations

None

E.F. Associated Documents

Link to the Implementation Plan and other important associated documents.
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A. Introduction

1. Title: Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology
2. Number: FAC-015-1
3. Purpose: To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator’s SOL Methodology.
4. Applicability:
   4.1. Functional Entities:
      4.1.1. Planning Coordinator
      4.1.2. Transmission Planner
5. Effective Date: See associated Implementation Plan.

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator’s SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator’s SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator’s SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator’s SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]
M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator’s SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator’s SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator’s. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);

6.2 The associated stability criteria used as part of determining the instability;

6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

• The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, “Compliance Monitoring and Enforcement Program” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
### FAC-015-1 – Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology

#### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</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>R1.</td>
<td>N/A</td>
<td>The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator’s SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.</td>
<td>The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator’s SOL Methodology, but did not document the technical justification.</td>
<td>The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in the Reliability Coordinator’s SOL Methodology.</td>
</tr>
<tr>
<td>R2.</td>
<td>N/A</td>
<td>The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator’s SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.</td>
<td>The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator’s SOL Methodology, but did not document the technical justification.</td>
<td>The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with the Reliability Coordinator’s SOL Methodology.</td>
</tr>
<tr>
<td>R3.</td>
<td>N/A</td>
<td>The Planning Coordinator used less limiting stability</td>
<td>The Planning Coordinator used less limiting stability</td>
<td>The Planning Coordinator failed to implement a</td>
</tr>
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<tr>
<td>R4.</td>
<td>N/A</td>
<td>N/A</td>
<td>The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to some but not all of its Transmission Planners. OR The Planning Coordinator failed to provide some of the required information.</td>
<td></td>
</tr>
<tr>
<td>R5.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were not equally or more limiting than those provided by its Planning Coordinator.</td>
</tr>
<tr>
<td>Requirement</td>
<td>Description</td>
<td></td>
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<tr>
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<tr>
<td>R6.</td>
<td>The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operators but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.</td>
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<tr>
<td></td>
<td>The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operators but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.</td>
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<tr>
<td></td>
<td>The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operators but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.</td>
<td></td>
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<tr>
<td></td>
<td>The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operators but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.</td>
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</table>

**D. Regional Variances**
None

**E. Interpretations**
None

**F. Associated Documents**
Implementation Plan
## Version History

<table>
<thead>
<tr>
<th>Version</th>
<th>Date</th>
<th>Action</th>
<th>Change Tracking</th>
</tr>
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<tbody>
<tr>
<td>1</td>
<td></td>
<td>Project 2015-09 SOL – Adopt new standard.</td>
<td>New</td>
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</table>
Proposed Definition of: “System Voltage Limit”

Term: “System Voltage Limit”

Definition:
The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for reliable System performance.

Rationale
The Project 2015-09 standard drafting team (SDT) proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for reliable System performance.

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 between July 14, 2016 and August 12, 2016, the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: “The maximum and minimum steady-state voltages (both normal and emergency) that provide for reliable system operations.”

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word “limits” was added to clarify that it is a numeric value.
- The terms “Normal” and “Emergency” were changed to lower case as “Normal” is not defined in the NERC Glossary, and the SDT concluded that the NERC Glossary definition for “Emergency” was not appropriate.
- The phrase “reliable system operations” was replaced with “acceptable System performance” because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term “System” as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a “System Voltage Limit” for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for
the Reliability Coordinator’s SOL Methodology to dictate the manner in which System Voltage Limits should established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT’s intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator’s SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator’s SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values.

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

**Potential Standards for Use of New Term: “System Voltage Limit”**

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control
Implementation Plan

Project 2015-09 Establish and Communicate System Operating Limits

Requested Approvals

- Definition of System Voltage Limit (SVL) in the Glossary of Terms Used in NERC Reliability Standards (“NERC Glossary”)
- FAC-011-4 System Operating Limits Methodology for the Operations Horizon
- FAC-014-3 Establish and Communicate System Operating Limits
- FAC-015-1 Coordination of Planning Assessments with the Reliability Coordinator’s SOL Methodology

Requested Retirements

- FAC-010-3 System Operating Limits Methodology for the Planning Horizon
- FAC-011-3 System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 Establish and Communicate System Operating Limits

Applicable Entities

- Reliability Coordinator
- Planning Coordinator
- Transmission Planner
- Transmission Operator

Effective Date

The effective date for proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015-1 and the NERC Glossary term “System Voltage Limit” is provided below:

Where approval by an applicable governmental authority is required, Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, and the NERC Glossary term “System Voltage Limit” shall become effective the first day of the first calendar quarter that is twelve (12) calendar months after the effective date of the applicable governmental authority’s order approving the standards and term, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standards FAC-011-4, FAC-014-3, FAC-015-1, and the NERC Glossary term “System Voltage Limit” shall become effective on the first day of the first calendar quarter that is twelve (12) calendar months after the
date the standards and term are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

**Initial Performance of Periodic Requirements**
**FAC-014-3 Requirement R5, Parts 5.1 and 5.2**
The initial performance of FAC-014-3, Requirement R5, Parts 5.1 and 5.2 must be within 12 calendar months of the effective date of FAC-014-3.

**Retirement Date**
**Currently-Effective NERC Reliability Standards**
Reliability Standards FAC-010-3, FAC-011-3, and FAC-014-2 shall be retired immediately prior to the effective date of the proposed Reliability Standards FAC-011-4, FAC-014-3, and FAC-015.
**Project 2015-10 Single Points of Failure TPL-001-5**

**Action**
Authorize the initial posting of proposed Reliability Standard TPL-001-5, the associated Implementation Plan, Violation Risk Factors (VRFs), and Violation Severity Levels (VSLs) for a 45-day formal comment period, a ballot pool formation during the first 30 days, and parallel initial ballot and non-binding poll held during the last 10 days of the comment period.

**Background**
Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754, issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee’s (SAMS) September 2015 report titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*;

- To address directives from FERC Order No. 786, issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4; and

- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

The Project 2015-10 standard drafting team (SDT) carefully reviewed and considered recommendations from the SAMS white paper\(^1\) as well as stakeholder comments received during an informal posting period. The revisions in proposed TPL-001-5 address the above directives and replace the Reliability Standard references.

Additionally, a quality review (QR) on the documents was performed between July 25 – August 8, 2017 by Johnathan Hayes (Southwest Power Pool), Ryan Mauldin (NERC Compliance), Soo Jin Kim (NERC, Manager of Standards Development), Ed Kichline (NERC Compliance Enforcement), Lauren Perotti (NERC Legal), Darrel Richardson (NERC Standards Development), and Wendy Muller (NERC Standards Information). The standard drafting team considered all QR inputs and revised the proposed standard where appropriate.

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\(^1\) The SAMS Whitepaper is available at: [FERC Order No. 786 Directives: NERC System Analysis and Modeling Subcommittee (SAMS) White Paper](https://www.nerc.com/).
Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

<table>
<thead>
<tr>
<th>Completed Actions</th>
<th>Date</th>
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</thead>
<tbody>
<tr>
<td>Standards Committee approved Standard Authorization Request (SAR) for posting</td>
<td>October 29, 2015</td>
</tr>
<tr>
<td>SAR posted for comment</td>
<td>May 26 – June 24, 2016</td>
</tr>
<tr>
<td>Informal Comment Period</td>
<td>April 25 – May 24, 2017</td>
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<td>30-day informal comment period with ballot</td>
<td>April 2017</td>
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<tr>
<td>45-day formal comment period with initial ballot</td>
<td>September 2017</td>
</tr>
<tr>
<td>45-day formal comment period with additional ballot</td>
<td>November 2017</td>
</tr>
<tr>
<td>10-day final ballot</td>
<td>February 2018</td>
</tr>
<tr>
<td>Board adoption</td>
<td>May 2018</td>
</tr>
</tbody>
</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.
A. Introduction

1. Title: Transmission System Planning Performance Requirements
2. Number: TPL-001-5
3. Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.
4. Applicability:
   4.1. Functional Entity
      4.1.1. Planning Coordinator.
      4.1.2. Transmission Planner.
5. Effective Date: See Implementation Plan.

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the -032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

1.1. System models shall represent:
   1.1.1. Existing Facilities
   1.1.2. Known outage(s) of generation or Transmission Facility(ies) as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.
   1.1.3. New planned Facilities and changes to existing Facilities
   1.1.4. Real and reactive Load forecasts
   1.1.5. Known commitments for Firm Transmission Service and Interchange
   1.1.6. Resources (supply or demand side) required for Load

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-032 including items represented in
the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.4.4. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

• Load level, Load forecast, or dynamic Load model assumptions.
• Expected transfers.
• Expected in service dates of new or modified Transmission Facilities.
• Reactive resource capability.
• Generation additions, retirements, or other dispatch scenarios.

2.4.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. 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 Scheme
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.
2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability
column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to
ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been
reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
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 identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

1.4. Compliance Monitoring Period and Reset Timeframe:

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

1.6. Additional Compliance Information:

None.
## Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</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>The responsible entity’s System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity’s System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity’s System model did not use data consistent with that provided in accordance with the MOD-032 standards and other sources, including items represented in the Corrective Action Plan.</td>
</tr>
<tr>
<td>R2.</td>
<td>The responsible entity failed to comply with Requirement R2, Part 2.6.</td>
<td>The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.</td>
<td>The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.</td>
<td>The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.</td>
</tr>
</tbody>
</table>
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R3.</td>
<td>The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as described in Requirement R3, Part 3.3 to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</td>
</tr>
<tr>
<td>R4.</td>
<td>The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR</td>
</tr>
</tbody>
</table>
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>R5.</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.</td>
<td>The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.</td>
<td></td>
<td>The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.</td>
</tr>
<tr>
<td>R6.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.</td>
</tr>
<tr>
<td>R7.</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.</td>
</tr>
</tbody>
</table>
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>
<tbody>
<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>February 8, 2005</td>
<td>BOT Approval</td>
<td>Revised</td>
</tr>
<tr>
<td>0</td>
<td>June 3, 2005</td>
<td>Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2</td>
<td>Errata</td>
</tr>
<tr>
<td>0</td>
<td>July 24, 2007</td>
<td>Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.</td>
<td>Errata</td>
</tr>
<tr>
<td>0.1</td>
<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to “0.1”</td>
<td>Errata</td>
</tr>
<tr>
<td>0.1</td>
<td>May 13, 2009</td>
<td>FERC Approved – Updated Effective Date and Footer</td>
<td>Revised</td>
</tr>
<tr>
<td>1</td>
<td>Approved by Board of Trustees February 17, 2011</td>
<td>Revised footnote ‘b’ pursuant to FERC Order RM06-16-009</td>
<td>Revised (Project 2010-11)</td>
</tr>
<tr>
<td>2</td>
<td>August 4, 2011</td>
<td>Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.</td>
<td>Project 2006-02 – complete revision</td>
</tr>
<tr>
<td>2</td>
<td>August 4, 2011</td>
<td>Adopted by Board of Trustees</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>April 19, 2012</td>
<td>FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC</td>
<td></td>
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<tr>
<td>Version</td>
<td>Date</td>
<td>Action</td>
<td>Change Tracking</td>
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</tr>
<tr>
<td></td>
<td></td>
<td>has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>February 7, 2013</td>
<td>Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote ‘b’ in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>February 7, 2013</td>
<td>Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>October 17, 2013</td>
<td>FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>May 7, 2014</td>
<td>NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.</td>
<td>Revision</td>
</tr>
<tr>
<td>4</td>
<td>November 26, 2014</td>
<td>FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>TBD</td>
<td>Adopted by the NERC Board of Trustees.</td>
<td>Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.</td>
</tr>
</tbody>
</table>
### Table 1 - Steady State & Stability Performance Planning Events

#### Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. 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.

#### Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

#### Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.
<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event</th>
<th>Fault Type</th>
<th>BES Level</th>
<th>Interruption of Firm Transmission Service Allowed</th>
<th>Non-Consequential Load Loss Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>P0</td>
<td>Normal System</td>
<td>None</td>
<td>N/A</td>
<td>EHV, HV</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>P2</td>
<td>Normal System</td>
<td>1. Opening of a line section w/o a fault 2. Bus Section Fault 3. Internal Breaker Fault (non-Bus-tie Breaker) 4. Internal Breaker Fault (Bus-tie Breaker)</td>
<td>N/A</td>
<td>EHV, HV</td>
<td>No⁹</td>
<td>No¹²</td>
</tr>
<tr>
<td>Category</td>
<td>Initial Condition</td>
<td>Event 1</td>
<td>Fault Type 2</td>
<td>BES Level 3</td>
<td>Interruption of Firm Transmission Service Allowed 4</td>
<td>Non-Consequential Load Loss Allowed</td>
</tr>
<tr>
<td>-------------------</td>
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<td>---------------------------------------------------</td>
<td>-------------------------------------</td>
</tr>
<tr>
<td>P3 Multiple Contingency</td>
<td>Loss of generator unit followed by System adjustments(^9)</td>
<td>Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6) 5. Single pole of a DC line</td>
<td>3Ø</td>
<td>EHV, HV</td>
<td>No(^9)</td>
<td>No(^12)</td>
</tr>
<tr>
<td>P4 Multiple Contingency (Fault plus stuck breaker(^{10}))</td>
<td>Normal System</td>
<td>Loss of multiple elements caused by a stuck breaker(^{10}) (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^5) 4. Shunt Device(^6) 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker(^{10}) (Bus-tie Breaker) attempting to clear a Fault on the associated bus</td>
<td>SLG</td>
<td>EHV</td>
<td>No(^9)</td>
<td>Yes</td>
</tr>
</tbody>
</table>

\(^{9}\) EHV No 12\(^{11}\)
<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event 1</th>
<th>Fault Type 2</th>
<th>BES Level 3</th>
<th>Interruption of Firm Transmission Service Allowed 4</th>
<th>Non-Consequential Load Loss Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)</td>
<td>Normal System</td>
<td>Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System(^{13}) protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer(^{5}) 4. Shunt Device(^{6}) 5. Bus Section</td>
<td>SLG</td>
<td>EHV</td>
<td>No(^{9})</td>
<td>No</td>
</tr>
<tr>
<td>P6 Multiple Contingency (Two overlapping singles)</td>
<td>Loss of one of the following followed by System adjustments(^{9}) 1. Transmission Circuit 2. Transformer(^{5}) 3. Shunt Device(^{6}) 4. Single pole of a DC line</td>
<td>Loss of one of the following: 1. Transmission Circuit 2. Transformer(^{5}) 3. Shunt Device(^{6}) 4. Single pole of a DC line</td>
<td>3Ø</td>
<td>EHV, HV</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>SLG</td>
<td>EHV, HV</td>
<td>Yes</td>
<td>Yes</td>
</tr>
<tr>
<td>Category</td>
<td>Initial Condition</td>
<td>Event 1</td>
<td>Fault Type 2</td>
<td>BES Level 3</td>
<td>Interruption of Firm Transmission Service Allowed</td>
<td>Non-Consequential Load Loss Allowed</td>
</tr>
<tr>
<td>---------------------------</td>
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<td>-------------------------------------------------</td>
<td>-------------------------------------</td>
</tr>
<tr>
<td>P7 Multiple Contingency</td>
<td>Normal System</td>
<td>The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure&lt;sup&gt;11&lt;/sup&gt; 2. Loss of a bipolar DC line</td>
<td>SLG</td>
<td>EHV, HV</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>

<sup>11</sup> Common Structure
### Table 1 - Steady State & Stability Performance Extreme Events

**Steady State & Stability**

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

**Steady State**

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.
   b. Loss of all Transmission lines on a common Right-of-Way.
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.

3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.

**Stability**

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing.
<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>ii.</td>
<td>Loss of the use of a large body of water as the cooling source for generation.</td>
</tr>
<tr>
<td>iii.</td>
<td>Wildfires.</td>
</tr>
<tr>
<td>iv.</td>
<td>Severe weather, e.g., hurricanes, tornadoes, etc.</td>
</tr>
<tr>
<td>v.</td>
<td>A successful cyber attack.</td>
</tr>
<tr>
<td>vi.</td>
<td>Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.</td>
</tr>
<tr>
<td>b.</td>
<td>Other events based upon operating experience that may result in wide area disturbances.</td>
</tr>
<tr>
<td>g.</td>
<td>3Ø fault on transformer with failure of a non-redundant component of a Protection System(^\text{13}) resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>h.</td>
<td>3Ø fault on bus section with failure of a non-redundant component of a Protection System(^\text{13}) resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>i.</td>
<td>3Ø internal breaker fault.</td>
</tr>
<tr>
<td>j.</td>
<td>Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.</td>
</tr>
</tbody>
</table>
### Table 1 - Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within
### Table 1 - Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)

<table>
<thead>
<tr>
<th>Footnote</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>10.</td>
<td>Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.</td>
</tr>
<tr>
<td>11.</td>
<td>An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.</td>
</tr>
<tr>
<td>12.</td>
<td>For purposes of this standard, non-redundant components of a Protection System to consider are as follows:</td>
</tr>
<tr>
<td>13.</td>
<td>For purposes of this standard, non-redundant components of a Protection System to consider are as follows:</td>
</tr>
<tr>
<td>1.</td>
<td>A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;</td>
</tr>
<tr>
<td>2.</td>
<td>A single communications system, necessary for correct operation of a communication-aid protection scheme required for Normal Clearing, which is not monitored or not reported;</td>
</tr>
<tr>
<td>3.</td>
<td>A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;</td>
</tr>
<tr>
<td>4.</td>
<td>A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.</td>
</tr>
</tbody>
</table>
Attachment 1

I. Stakeholder Process
During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process
The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV

   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or

   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)

2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.
Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

<table>
<thead>
<tr>
<th>Completed Actions</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standards Committee approved Standard Authorization Request (SAR) for posting</td>
<td>October 29, 2015</td>
</tr>
<tr>
<td>SAR posted for comment</td>
<td>May 26 – June 24, 2016</td>
</tr>
<tr>
<td>Informal Comment Period</td>
<td>April 25 – May 24, 2017</td>
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<tr>
<td>45-day formal comment period with additional ballot</td>
<td>November 2017</td>
</tr>
<tr>
<td>10-day final ballot</td>
<td>February 2018</td>
</tr>
<tr>
<td>Board adoption</td>
<td>May 2018</td>
</tr>
</tbody>
</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.
A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: TPL-001-45

3. Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. Applicability:
   4.1. Functional Entity
      
      4.1.1. Planning Coordinator.
      4.1.2. Transmission Planner.

5. Effective Date: Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

   For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:

   - P1–2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P1–3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
   - P2–1
   - P2–2 (above 300 kV)
   - P2–3 (above 300 kV)
   - P3–1 through P3–5
5. Requirements

**Effective Date:** See Implementation Plan.

### B. Requirements and Measures

**R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **[Violation Risk Factor: High] [Time Horizon: Long-term Planning]**

1. System models shall represent:

   1.1. Existing Facilities

   1.1.1. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months, as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

   1.1.2. New planned Facilities and changes to existing Facilities

   1.1.3. Real and reactive Load forecasts

   1.1.4. Resources (supply or demand side) required for Load

   1.1.5. Known commitments for Firm Transmission Service and Interchange

   1.1.6. Known facilities for Firm Transmission Service and Interchange

**M1.** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with MOD-010 and MOD-012, MOD-032 including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

**R2.** Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short
circuit analyses, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:
2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part 2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.4.4. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.4.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible
unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. 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 Scheme.
• Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
• Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
• Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
• Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has
prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

   3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

      3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

      3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System Remédial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.
R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
B.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 Compliance Enforcement Authority

Each Responsible Entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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

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

1.4. Compliance Monitoring Period and Reset Timeframe

1.5. Compliance Monitoring and Enforcement Processes:
1.3 Additional Compliance Information

1.6. None
## Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</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>The responsible entity’s System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.</td>
<td>The responsible entity’s System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity’s System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity’s System model did not use data consistent with that provided in accordance with the MOD-010 and MOD-012 –MOD-032 standards and other sources, including items represented in the Corrective Action Plan.</td>
</tr>
<tr>
<td>R2.</td>
<td>The responsible entity failed to comply with Requirement R2, Part 2.6.</td>
<td>The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.</td>
<td>The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.</td>
<td>The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.</td>
</tr>
</tbody>
</table>
### R3.
The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.

<table>
<thead>
<tr>
<th>Violation Severity Levels</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</td>
<td>The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.</td>
<td></td>
</tr>
</tbody>
</table>

### R4.
The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.

<table>
<thead>
<tr>
<th>Violation Severity Levels</th>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR</td>
<td>The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR</td>
<td></td>
</tr>
<tr>
<td>R #</td>
<td>Lower VSL</td>
<td>Moderate VSL</td>
<td>High VSL</td>
<td>Severe VSL</td>
</tr>
<tr>
<td>-----</td>
<td>----------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| R5  | The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events. | The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3. OR The responsible entity did not develop a Corrective Action Plan as described in Requirement R4, Part 4.6. | The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1. |}

| R6  | N/A                                                                        | N/A                                                                        | N/A                                                                        | The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6. |
| R7  | N/A                                                                        | N/A                                                                        | N/A                                                                        | The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies. |
C.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>
<tbody>
<tr>
<td>0</td>
<td>April 1, 2005</td>
<td>Effective Date</td>
<td>New</td>
</tr>
<tr>
<td>0</td>
<td>February 8, 2005</td>
<td>BOT Approval</td>
<td>Revised</td>
</tr>
<tr>
<td>0</td>
<td>June 3, 2005</td>
<td>Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2</td>
<td>Errata</td>
</tr>
<tr>
<td>0</td>
<td>July 24, 2007</td>
<td>Corrected reference in M1 to read TPL-001-0 R1 and TPL-001-0 R2.</td>
<td>Errata</td>
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<tr>
<td>0.1</td>
<td>October 29, 2008</td>
<td>BOT adopted errata changes; updated version number to “0.1”</td>
<td>Errata</td>
</tr>
<tr>
<td>0.1</td>
<td>May 13, 2009</td>
<td>FERC Approved – Updated Effective Date and Footer</td>
<td>Revised</td>
</tr>
<tr>
<td>1</td>
<td>Approved by Board of Trustees February 17, 2011</td>
<td>Revised footnote 'b' pursuant to FERC Order RM06-16-009</td>
<td>Revised (Project 2010-11)</td>
</tr>
<tr>
<td>2</td>
<td>August 4, 2011</td>
<td>Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.</td>
<td>Project 2006-02 – complete revision</td>
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<tr>
<td>2</td>
<td>August 4, 2011</td>
<td>Approved by Board of Trustees</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>April 19, 2012</td>
<td>FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC</td>
<td></td>
</tr>
</tbody>
</table>
Version | Date       | Action                                                                                                                                                                                                 |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>February 7, 2013</td>
<td>Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.</td>
</tr>
<tr>
<td>4</td>
<td>February 7, 2013</td>
<td>Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.</td>
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<tr>
<td>4</td>
<td>October 17, 2013</td>
<td>FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).</td>
</tr>
<tr>
<td>4</td>
<td>May 7, 2014</td>
<td>NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.</td>
</tr>
<tr>
<td>4</td>
<td>November 26, 2014</td>
<td>FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.</td>
</tr>
<tr>
<td>5</td>
<td>TBD</td>
<td>Adopted by the NERC Board of Trustees. Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.</td>
</tr>
</tbody>
</table>
I. **Stakeholder Process**

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity may utilize an existing process or develop a new process. The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.

2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period

3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants.

4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns.

5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction.

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. **Information for Inclusion in Item #3 of the Stakeholder Process**

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)

The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW. Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.
### Table 1 - Steady State & Stability Performance Planning Events

<table>
<thead>
<tr>
<th>Steady State &amp; Stability:</th>
</tr>
</thead>
<tbody>
<tr>
<td>a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.</td>
</tr>
<tr>
<td>b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.</td>
</tr>
<tr>
<td>c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.</td>
</tr>
<tr>
<td>d. Simulate Normal Clearing unless otherwise specified.</td>
</tr>
<tr>
<td>e. 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.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Steady State Only:</th>
</tr>
</thead>
<tbody>
<tr>
<td>f. Applicable Facility Ratings shall not be exceeded.</td>
</tr>
<tr>
<td>g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.</td>
</tr>
<tr>
<td>h. Planning event P0 is applicable to steady state only.</td>
</tr>
<tr>
<td>i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Stability Only:</th>
</tr>
</thead>
<tbody>
<tr>
<td>j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.</td>
</tr>
<tr>
<td>Category</td>
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<tr>
<td>----------</td>
</tr>
<tr>
<td>P0</td>
</tr>
<tr>
<td>P1</td>
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<tr>
<td>P2</td>
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<tr>
<td>Category</td>
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<td>---------------------------</td>
</tr>
<tr>
<td><strong>P3</strong> Multiple Contingency</td>
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<tr>
<td><strong>P4</strong> Multiple Contingency (Fault plus stuck breaker$^{10}$)</td>
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<tr>
<td>Category</td>
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</tr>
<tr>
<td>P5 Multiple Contingency</td>
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<tr>
<td></td>
</tr>
<tr>
<td>P6 Multiple Contingency</td>
</tr>
</tbody>
</table>

Draft 1 of TPL-001-5
September 2017
<table>
<thead>
<tr>
<th>Category</th>
<th>Initial Condition</th>
<th>Event 1</th>
<th>Fault Type 2</th>
<th>BES Level 3</th>
<th>Interruption of Firm Transmission Service Allowed 4</th>
<th>Non-Consequential Load Loss Allowed</th>
</tr>
</thead>
<tbody>
<tr>
<td>P7</td>
<td>Normal System</td>
<td>The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure 11 2. Loss of a bipolar DC line</td>
<td>SLG</td>
<td>EHV, HV</td>
<td>Yes</td>
<td>Yes</td>
</tr>
</tbody>
</table>
Table 1 - Steady State & Stability Performance Extreme Events

**Steady State & Stability**
For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
b. Simulate Normal Clearing unless otherwise specified.

<table>
<thead>
<tr>
<th>Steady State</th>
<th>Stability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.</td>
<td>1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.</td>
</tr>
<tr>
<td>2. Local area events affecting the Transmission System such as:</td>
<td>2. Local or wide area events affecting the Transmission System such as:</td>
</tr>
<tr>
<td>a. Loss of a tower line with three or more circuits.</td>
<td>a. 3Ø fault on generator with stuck breaker\textsuperscript{10} or a relay failure\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>b. Loss of all Transmission lines on a common Right-of-Way\textsuperscript{11}.</td>
<td>b. 3Ø fault on Transmission circuit with stuck breaker\textsuperscript{10} or a relay failure\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>c. Loss of a switching station or substation (loss of one voltage level plus transformers).</td>
<td>c. 3Ø fault on transformer with stuck breaker\textsuperscript{10} or a relay failure\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>d. Loss of all generating units at a generating station.</td>
<td>d. 3Ø fault on bus section with stuck breaker\textsuperscript{10} or a relay failure\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>e. Loss of a large Load or major Load center.</td>
<td>e. 3Ø fault on generator with failure of a non-redundant component of a Protection System\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>3. Wide area events affecting the Transmission System based on System topology such as:</td>
<td>f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System\textsuperscript{13} resulting in Delayed Fault Clearing.</td>
</tr>
<tr>
<td>a. Loss of two generating stations resulting from conditions such as:</td>
<td></td>
</tr>
<tr>
<td>i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.</td>
<td></td>
</tr>
<tr>
<td>ii. Loss of the use of a large body of water as the cooling source for generation.</td>
<td></td>
</tr>
</tbody>
</table>
iii. Wildfires.
iv. Severe weather, e.g., hurricanes, tornadoes, etc.
v. A successful cyber attack.
v. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants.
b. Other events based upon operating experience that may result in wide area disturbances.

g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing.
h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing.
i. 3Ø internal breaker fault.
j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.
Table 1 - Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner’s planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.
Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

   1. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;
   2. A single communications system, necessary for correct operation of a communication-aid protection scheme required for Normal Clearing, which is not monitored or not reported;
   3. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;
   4. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices. Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).
Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

6.1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

7.2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period

8.3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants

9.4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns

10.5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

9.1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

10.2. Amount of Non-Consequential Load Loss with:
   a. The estimated number and type of customers affected
b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

11.3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

12.4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

13.5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

14.6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

15.7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

16.8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

2.1. The voltage level of the Contingency is greater than 300 kV
   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or
   b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)

3-2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any
Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.
Implementation Plan
Project 2015-10 Single Points of Failure
Reliability Standard TPL-001-5

Applicable Standard(s)
- TPL-001-5 – Transmission System Planning Performance Requirements

Requested Retirement(s)
- TPL-001-4 – Transmission System Planning Performance Requirements

Prerequisite Standard(s)
- None

Applicable Entities
- Planning Coordinator
- Transmission Planner

Background
Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754 issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee September 2015 report titled Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;

- To address directives from FERC Order No. 786 issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4; and

- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations
The 36-month implementation period for TPL-001-5 provides Planning Coordinators and Transmission Planners with time to update their annual Planning Assessments to include the new System models and studies required by the standard. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time to develop, among other things:
• A process for coordinating with the Reliability Coordinator which known outages of generation of Transmission Facilities of less than six months shall be represented in planning studies;

• A process for establishing coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and

• Additional base case models and analysis.

In addition, the implementation plan includes an additional 24 month period for the development of Corrective Action Plans under TPL-001-5 to address newly-added studies involving single points of failure on Protection Systems. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time beyond that provided to conduct the new studies and analysis to develop processes for coordination with asset owners and protection engineers to identify appropriate Corrective Action Plan actions and establish the associated timetables for completion. This includes any necessary Corrective Action Plans to address System performance issues for studies involving Table 1 Category P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2 Part 2.7 for the following non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13, items 2-4:

• A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

• A single direct current (dc) supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

• A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Lastly, the provisions related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) are carried forward from the TPL-001-4 implementation plan.

**Effective Date**

**TPL-001-5 – Transmission System Planning Performance Requirements**

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 36 months after the effective date of the applicable governmental authority’s order approving the standard, or as otherwise provided 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 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.
Compliance Date for TPL-001-5 Requirement 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items 2, 3, and 4
Entitles shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items 2, 3, and 4 until 24 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding Corrective Action Plans
For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval of TPL-001-4, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-5:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

Initial Performance of Periodic Requirements
Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall complete any required Corrective Action Plans under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13 items 2, 3, and 4 by 24 months after the effective date of Reliability Standard TPL-001-5.

Retirement Date
TPL-001-4 – Transmission System Planning Performance Requirements
Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5 in the particular jurisdiction in which the revised standard is becoming effective.
Violation Risk Factor and Violation Severity Level Justifications
Project 2015-10 Single Points of Failure TPL-001

This document provides the standard drafting team’s (SDT’s) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Requirement R4 in Project 2015-10 and Single Points of Failure TPL-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

**High Risk Requirement**
A requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

**Medium Risk Requirement**
A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
**Lower Risk Requirement**
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.

**FERC Guidelines for Violation Risk Factors**

**Guideline (1) - Consistency with the Conclusions of the Final Blackout Report**
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the bulk power system. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the bulk power system:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief
Guideline (2) - Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) - Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) - Consistency with NERC’s Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) - Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.
NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

<table>
<thead>
<tr>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>The performance or product measured almost meets the full intent of the requirement.</td>
<td>The performance or product measured meets the majority of the intent of the requirement.</td>
<td>The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.</td>
<td>The performance or product measured does not substantively meet the intent of the requirement.</td>
</tr>
</tbody>
</table>

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

**Guideline (1) - Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance**

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

**Guideline (2) - Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties**

A violation of a “binary” type requirement must be a “Severe” VSL.

Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

**Guideline (3) - Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement**

VSLs should not expand on what is required in the requirement.
Guideline (4) - Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

**VRF Justification for TPL-001-5, Requirement R1**
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VSL Justification for TPL-001-5, Requirement R1**
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VRF Justification for TPL-001-5, Requirement R2**
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VSL Justification for TPL-001-5, Requirement R2**
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VRF Justification for TPL-001-5, Requirement R3**
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VSL Justification for TPL-001-5, Requirement R3**
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VRF Justification for TPL-001-5, Requirement R4**
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

**VSL Justification for TPL-001-5, Requirement R4**
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.
VRF Justification for TPL-001-5, Requirement R5
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R5
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R6
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R6
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R7
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R7
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R8
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R8
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.
Project 2016-02 Modifications to CIP Standards

Action
Authorize initial posting of proposed Reliability Standard CIP-002-6, its associated Implementation Plan, Violation Risk Factors, and Violation Severity Levels for a 45-day formal comment period with parallel initial ballot and non-binding poll during the last 10 days of the comment period.

Background
Project 2016-02 addresses the Federal Energy Regulatory Commission (FERC) Order No. 822 directives and considers the Version 5 Transition Advisory Group (V5TAG) recommendations identified in the CIP Version 5 Issues for Standard Drafting Team Consideration. In response to the V5TAG recommendation regarding clarification of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12., the Project 2016-02 standard drafting team (SDT) proposes modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements to a Control Center that performs the functional obligations of a Transmission Operator.

The proposed criterion establishes an average MVA line loading, based on voltage class, for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12 and can be calculated by summing the "weight value per line" shown in the associated table for each Bulk Electric System (BES) Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weight value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) must be identified as medium impact. If the aggregate weight value of lines does not exceed 6000, the Control Center’s associated BES Cyber System(s) must be evaluated for classification as low impact pursuant to Criterion 3.1.

The Quality Review (QR) for this posting was performed August 3-10, 2017 by Ash Mayfield (Grand River Dam Authority), Jerry Freese (Northern Indiana Public Service Co.), David Revill, and Christine Hasha (SDT leadership), and Shamai Elstein and Marisa Hecht (NERC Legal staff). The QR team reviewed the documents and provided feedback to the SDT. The SDT considered the feedback, made appropriate modifications to the draft documents, and approved submitting the final documents to the Standards Committee for authorization to post.
A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-6

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

4. **Applicability:**

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

   4.1.1. **Balancing Authority**

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

   - **4.1.2.1.** Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:
     - **4.1.2.1.1.** is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
     - **4.1.2.1.2.** performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
   
   - **4.1.2.2.** Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

   - **4.1.2.4.** Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
4.1.3. Generator Operator
4.1.4. Generator Owner
4.1.5. Reliability Coordinator
4.1.6. Transmission Operator
4.1.7. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:
   4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
   4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each Remedial Action Scheme where the Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

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

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

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.
4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

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

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

5. **Effective Dates:**

See implementation plan for CIP-002-6.

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

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

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

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

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

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a security plan for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.
It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

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

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

**Categorization Criteria**
The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.
This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

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

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Compliance Monitoring Process:

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

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

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information:
None.
## Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels (CIP-002-5.1a)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Lower VSL</strong></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five</td>
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<tr>
<td></td>
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<td></td>
<td>percent or fewer BES assets have not been considered according to Requirement R1; OR</td>
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<tr>
<td></td>
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<td>For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement</td>
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<tr>
<td></td>
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<td></td>
<td>R1, have not been considered according to Requirement R1; OR</td>
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<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
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<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five</td>
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<td>percent but less than or equal to 10 percent of BES assets have not been considered, according to</td>
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<td>Requirement R1; OR</td>
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<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10</td>
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<td></td>
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<td>percent but less than or equal to 15 percent of BES assets have not been considered, according to</td>
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<td></td>
<td></td>
<td>Requirement R1; OR</td>
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<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>percent of BES assets have not been considered, according to Requirement R1; OR</td>
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<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets, more than six BES assets in</td>
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<tr>
<td></td>
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<td></td>
<td>Requirement R1, have not been considered according to Requirement R1; OR</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels (CIP-002-5.1a)</td>
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<td></td>
<td></td>
<td><strong>Lower VSL</strong></td>
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<td></td>
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<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Moderate VSL</strong></td>
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<td></td>
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<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>High VSL</strong></td>
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<tr>
<td></td>
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<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td><strong>Severe VSL</strong></td>
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<tr>
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<td>Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
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<td>OR</td>
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<td></td>
<td>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</td>
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<tr>
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<td>OR</td>
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<td></td>
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<td>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
</tr>
<tr>
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<td>OR</td>
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<td>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized at a lower category.</td>
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<td>OR</td>
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<tr>
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<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>OR</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>OR</td>
</tr>
</tbody>
</table>
|     |              |     | For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Lower VSL</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</td>
</tr>
</tbody>
</table>

**Violation Severity Levels (CIP-002-5.1a)**

<table>
<thead>
<tr>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</td>
<td>Systems, five percent or fewer high or medium BES Cyber Systems have not been categorized at a lower category. OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.</td>
<td>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</td>
<td>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td>Violation Severity Levels (CI P-002-5.1a)</td>
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<td>----------------------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Lower VSL</td>
</tr>
<tr>
<td>R2.</td>
<td>Operations Planning</td>
<td>Lower</td>
<td>The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Moderate VSL</td>
</tr>
<tr>
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<td></td>
<td></td>
<td>The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>High VSL</td>
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<td></td>
<td></td>
<td>The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Severe VSL</td>
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<tr>
<td></td>
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<td></td>
<td>The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)</td>
</tr>
</tbody>
</table>
D. Regional Variances
None.

E. Interpretations
See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

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>1/16/06</td>
<td>R3.2 — Change “Control Center” to “control center.”</td>
<td>3/24/06</td>
</tr>
<tr>
<td>2</td>
<td>9/30/09</td>
<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>12/16/09</td>
<td>Updated version number from -2 to -3. Approved by the NERC Board of Trustees.</td>
<td>Update</td>
</tr>
<tr>
<td>3</td>
<td>3/31/10</td>
<td>Approved by FERC.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>12/30/10</td>
<td>Modified to add specific criteria for Critical Asset identification.</td>
<td>Update</td>
</tr>
<tr>
<td>4</td>
<td>1/24/11</td>
<td>Approved by the NERC Board of Trustees.</td>
<td>Update</td>
</tr>
<tr>
<td>5</td>
<td>11/26/12</td>
<td>Adopted by the NERC Board Trustees.</td>
<td>Modified to coordinate with other CIP standards and to revise format to use RBS Template.</td>
</tr>
<tr>
<td>5.1</td>
<td>9/30/13</td>
<td>Replaced “Devices” with “Systems” in a definition in background section.</td>
<td>Errata</td>
</tr>
<tr>
<td>Version</td>
<td>Date</td>
<td>Action</td>
<td>Change Tracking</td>
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<td>5.1</td>
<td>11/22/13</td>
<td>FERC Order issued approving CIP-002-5.1.</td>
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</tr>
<tr>
<td>5.1a</td>
<td>11/02/16</td>
<td>Adopted by the NERC Board of Trustees.</td>
<td></td>
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<tr>
<td>6</td>
<td>TBD</td>
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</tr>
</tbody>
</table>
Attachment 1

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

1. High Impact Rating (H)
   Each BES Cyber System used by and located at any of the following:
   1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
   1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
   1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
   1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)
   Each BES Cyber System, not included in Section 1 above, associated with any of the following:
   2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
   2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
   2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

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

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 200 kV (not applicable)</td>
<td>(not applicable)</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
</tr>
</tbody>
</table>

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

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

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

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

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

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

Rationale for Criterion 2.12: The V5 Transition Advisory Group (VSTAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. During the course of the VSTAG’s activities, the VSTAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The VSTAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document\(^1\) to formally recommend that the SDT address these issues during the standards development process and to consider modifications to the standard language.

Among other issues, due to the confusion of the application of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the VSTAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12, and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be evaluated for classification as low impact pursuant to Criterion 3.1.

2.12. Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value"

\(^1\) This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_VSTAG-SDT_1st-final-03232016.pdf.
for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV (not applicable)</td>
<td>(not applicable)</td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
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<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
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<tr>
<td>500 kV and above</td>
<td>0</td>
</tr>
</tbody>
</table>

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

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

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

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

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

3.5. Remedial Action Schemes that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
Guidelines and Technical Basis

At NERC’s direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

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

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

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

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-6

CIP-002-6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”
The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-6. The concept includes a number of named BES reliability operating services. These named services include:

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

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

<table>
<thead>
<tr>
<th>Entity Registration</th>
<th>RC</th>
<th>BA</th>
<th>TOP</th>
<th>TO</th>
<th>DP</th>
<th>GOP</th>
<th>GO</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dynamic Response</td>
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<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<td>X</td>
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<tr>
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<td></td>
<td>X</td>
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<td></td>
<td>X</td>
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<tr>
<td>Controlling Voltage</td>
<td></td>
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<td>X</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
</tr>
<tr>
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<td>Restoration</td>
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<td></td>
<td>X</td>
<td></td>
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<tr>
<td>Situation Awareness</td>
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<td>X</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Inter-Entity coordination</td>
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<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>
Dynamic Response
The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

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

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

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

Manually Initiated Load shedding
- Ability to identify load change need (BA)
- Ability to implement load changes (TOP, DP)

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

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

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)

- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

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

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)

- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO, DP)

- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP, TO, DP)

- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO, DP)
Managing Constraints
Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

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

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

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

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

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

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

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

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

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

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

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

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

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

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a
line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

**High Impact Rating (H)**

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAs, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.
The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BAs with significant impact are covered under this criterion.

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

**Medium Impact Rating (M)**

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

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

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

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

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

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

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

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

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

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

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

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

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

**Transmission**

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

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

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

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

- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.
The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

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

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

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

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

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

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.
Criterion 2.5’s qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4.: there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

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

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

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

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

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

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

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

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

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

- Criterion 2.12 categorizes medium impact BES Cyber Systems associated with Control Centers and backup Control Centers, including associated data centers, that monitor and control BES Transmission Lines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission
Control Centers validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV and are monitored and controlled by a Control Center, including associated data center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are monitored and controlled by the Responsible Entity’s Control Center, including associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line.

**Criterion 2.12 Examples:**

In example 1 below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.

![Example 1 Diagram](image_url)

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).
In the additional example below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.

**Example 2**

All Transmission Lines are operated at 138 kV in this example.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
<th>Applicable Lines</th>
<th>Weighted Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV (not applicable)</td>
<td>(not applicable)</td>
<td>Line 5</td>
<td>N/A</td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
<td>Line 1, Line 2, Line 3, Line 4, Line 7</td>
<td>3500</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
<td>Line 6, Line 8</td>
<td>2600</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
<td>None</td>
<td>0</td>
</tr>
</tbody>
</table>

Calculation

\[ 700 + 700 + 700 + 700 + 700 + 1300 + 1300 + 1300 = 6100 \]
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System associated with the Control Center in this example should be categorized as a low impact BES Cyber System pursuant to Criterion 3.1.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
<th>Applicable Lines</th>
<th>Weighted Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV</td>
<td>(not applicable)</td>
<td>None</td>
<td>N/A</td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
<td>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</td>
<td>2000</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
<td>None</td>
<td>0</td>
</tr>
</tbody>
</table>

Calculation


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

**Low Impact Rating (L)**

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

**Restoration Facilities**

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.
In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

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

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

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

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

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

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

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

**Overview (Generation Facility)**

- Identify & Categorize BES Cyber Assets and BES Cyber Systems
  - Engineering revisions to reduce impact a BES Cyber System has on a Facility*
  - Evaluate BES Cyber Assets and BES Cyber Systems for External Routable Connectivity
  - Engineering revisions to reduce or eliminate External Routable Connectivity*
  - Identify final Electronic Access Points and Electronic Access Control Systems

- Evaluate potential Physical Security Perimeters
  - Engineering revisions to reduce or eliminate physical areas*
  - Identify final Physical Security Perimeters and Physical Access Control Systems
  - Apply Security Controls based on applicability

* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.
Rationale
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:
BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:
The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.
## Appendix 1

### Requirement Number and Text of Requirement

<table>
<thead>
<tr>
<th>Requirement Number and Text of Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>CIP-002-5.1, Requirement R1</td>
</tr>
</tbody>
</table>

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

i. Control Centers and backup Control Centers;

ii. Transmission stations and substations;

iii. Generation resources;

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

v. Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and

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

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

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

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

### Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

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

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

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

**Responses**

**Question 1:** Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2...” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “Each BES Cyber System...associated with any of the following [criteria].” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.
Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

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

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

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

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

The phrase applies to each discrete BES Cyber System.
A. Introduction

1. Title: Cyber Security — BES Cyber System Categorization

2. Number: CIP-002-5.1a6

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

4. Applicability:

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

4.1.1. Balancing Authority

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

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

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

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

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

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

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

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

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

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

4.2.1.1. Each UFLS or UVLS System that:

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

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

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

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

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.
4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-5.1a6:

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

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

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

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

5. Effective Dates:

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

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

See implementation plan for CIP-002-6.

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

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

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

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

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

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

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

**Reliable Operation of the BES**

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

**Real-time Operations**

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

**Categorization Criteria**

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.
This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

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

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

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

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

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

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

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

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

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

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

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

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

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

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

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

1. Compliance Monitoring Process:

   1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority (“CEA”) unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

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

   The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

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

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

   • The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. Compliance Monitoring and Assessment Processes:

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

   1.4. Additional Compliance Information:

   None.
### Violation Severity Levels

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
<th>Violation Severity Levels (CIP-002-5.1a)</th>
</tr>
</thead>
<tbody>
<tr>
<td>R1.</td>
<td>Operations Planning</td>
<td>High</td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber</td>
</tr>
<tr>
<td>R #</td>
<td>Time Horizon</td>
<td>VRF</td>
<td></td>
</tr>
<tr>
<td>-----</td>
<td>--------------</td>
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<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Violation Severity Levels (CIP-002-5.1a)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Lower VSL</strong></td>
</tr>
<tr>
<td>Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
</tr>
<tr>
<td>OR</td>
</tr>
<tr>
<td>For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.</td>
</tr>
<tr>
<td>OR</td>
</tr>
<tr>
<td>For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;</td>
</tr>
<tr>
<td>OR</td>
</tr>
<tr>
<td>For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized.</td>
</tr>
</tbody>
</table>

| **Moderate VSL**                          |
| For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; |
| OR                                      |
| For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Assets, more than 10 but less than or equal to 15 identified BES Cyber Assets have not been categorized or have been incorrectly categorized. |

| **High VSL**                              |
| Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; |
| OR                                      |
| For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized. |

| **Severe VSL**                            |
| For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. |
### Violation Severity Levels (CIP-002-5.1a)

<table>
<thead>
<tr>
<th>R #</th>
<th>Time Horizon</th>
<th>VRF</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.</th>
</tr>
</thead>
<tbody>
<tr>
<td>categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.</td>
</tr>
<tr>
<td>categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 high or medium BES Cyber Systems have not been identified.</td>
</tr>
<tr>
<td>Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.</td>
</tr>
<tr>
<td>R #</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>R2.</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
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</tr>
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</table>
D. Regional Variances
None.

E. Interpretations
See Appendix 1. The Interpretation in Appendix 1 was developed under a prior version of the Reliability Standard, CIP-002-5.1, and is being carried forward to subsequent versions.

E.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>1/16/06</td>
<td>R3.2 — Change “Control Center” to “control center.”</td>
<td>3/24/06</td>
</tr>
<tr>
<td>2</td>
<td>9/30/09</td>
<td>Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Removal of reasonable business judgment.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Replaced the RRO with the RE as a Responsible Entity.</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Rewording of Effective Date.</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Changed compliance monitor to Compliance Enforcement Authority.</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>12/16/09</td>
<td>Updated version number from -2 to -3. Approved by the NERC Board of Trustees.</td>
<td>Update</td>
</tr>
<tr>
<td>3</td>
<td>3/31/10</td>
<td>Approved by FERC.</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>12/30/10</td>
<td>Modified to add specific criteria for Critical Asset identification.</td>
<td>Update</td>
</tr>
<tr>
<td>4</td>
<td>1/24/11</td>
<td>Approved by the NERC Board of Trustees.</td>
<td>Update</td>
</tr>
<tr>
<td>5</td>
<td>11/26/12</td>
<td>Adopted by the NERC Board Trustees.</td>
<td></td>
</tr>
<tr>
<td>5.1</td>
<td>9/30/13</td>
<td>Replaced “Devices” with “Systems” in a definition in background section.</td>
<td>Errata</td>
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<tr>
<td>Version</td>
<td>Date</td>
<td>Action</td>
<td>Change Tracking</td>
</tr>
<tr>
<td>---------</td>
<td>------------</td>
<td>------------------------------------------------------------------------</td>
<td>-----------------</td>
</tr>
<tr>
<td>5.1</td>
<td>11/22/13</td>
<td>FERC Order issued approving CIP-002-5.1.</td>
<td></td>
</tr>
<tr>
<td>5.1a</td>
<td>11/02/16</td>
<td>Adopted by the NERC Board of Trustees.</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>TBD</td>
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<td></td>
</tr>
</tbody>
</table>
Attachment 1

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

1. High Impact Rating (H)
   Each BES Cyber System used by and located at any of the following:
   1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.
   1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.
   1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.
   1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)
   Each BES Cyber System, not included in Section 1 above, associated with any of the following:
   2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
   2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.
   2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.
2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

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

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 200 kV (not applicable)</td>
<td>(not applicable)</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
</tr>
</tbody>
</table>

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

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

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

2.9. Each Special Protection System (SPS), Remedial Action Scheme (RAS), or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.
2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

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

Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.

Rationale for Criterion 2.12: The V5 Transition Advisory Group (V5TAG), which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry’s implementation activities. During the course of the V5TAG’s activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by a standard drafting team (SDT) for the CIP Reliability Standards. The V5TAG developed the CIP Version 5 Transition Advisory Group Issues for Consideration document¹ to formally recommend that the SDT address these issues during the standards development process and to consider modifications to the standard language.

Among other issues, due to the confusion of the application of the phrase “used to perform the functional obligations of the Transmission Operator” in CIP-002-5.1a, Attachment 1, Criterion 2.12, the V5TAG recommended clarification of the criterion.

The Project 2016-02 Standard Drafting Team (SDT) proposes the following modifications to CIP-002-5.1a, Attachment 1, Criterion 2.12 to clarify the applicability of requirements on a TO Control Center that performs the functional obligations of a TOP.

The proposed criterion establishes a weighted value for BES Transmission Lines based on voltage class for BES Transmission Lines operated between 100 and 499 kV. The aggregate weighted value for applicable BES Cyber Systems must exceed 6000 to meet the minimum threshold established in Criterion 2.12, and can be calculated by summing the "weight value per line" shown in the associated table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center. If the aggregate weighted value of lines exceed 6000, the Control Center’s associated BES Cyber System(s) should be identified as medium impact. If the aggregate weighted value of lines do not exceed 6000, the Control Center’s associated BES Cyber System(s) should be evaluated for classification as low impact pursuant to Criterion 3.1.

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¹ This document is available at http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/Transfer_Issues_V5TAG-SDT_1st-final-03232016.pdf.
2.12. Control Centers or backup Control Centers, not included in High Impact Rating (H) above, that monitor and control BES Transmission Lines with an "aggregate weighted value" exceeding 6000 according to the table below. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV (not applicable)</td>
<td>(not applicable)</td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
</tr>
</tbody>
</table>

2.12.2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

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

3.1. Control Centers and backup Control Centers.
3.2. Transmission stations and substations.
3.3. Generation resources.
3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.
3.5. Special Protection Systems Remedial Action Schemes that support the reliable operation of the Bulk Electric System.
3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.
Guidelines and Technical Basis

At NERC’s direction, the current draft Guidelines and Technical Basis section will be removed from the Reliability Standard template prior to final ballot. The SDT will evaluate the content for placement in a Technical Rationale document for posting along with, but separate from, the Reliability Standard. Additionally, the SDT may develop Implementation Guidance on this Reliability Standard to submit for ERO endorsement based on the content of this section.

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

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

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

Section “4.2. Facilities” defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term “Facilities” already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a6 and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a6. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002-5.1a6

CIP-002-5.1a6 requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, “...that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES.”
The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a6. The concept includes a number of named BES reliability operating services.
These named services include:

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

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

<table>
<thead>
<tr>
<th>Entity Registration</th>
<th>RC</th>
<th>BA</th>
<th>TOP</th>
<th>TO</th>
<th>DP</th>
<th>GOP</th>
<th>GO</th>
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<tbody>
<tr>
<td>Dynamic Response</td>
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<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Balancing Load &amp; Generation</td>
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<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Controlling Frequency</td>
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<td>X</td>
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<td>X</td>
</tr>
<tr>
<td>Controlling Voltage</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
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<tr>
<td>Managing Constraints</td>
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<td>X</td>
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<td>X</td>
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<td></td>
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<tr>
<td>Monitoring and Control</td>
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<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>
Dynamic Response
The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

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

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

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
- Ability to implement load changes (TOP, DP)
- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

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

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

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

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO, DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP, TO, DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO, DP)
Managing Constraints
Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

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

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

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

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

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

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

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

Frequency monitoring (BA, RC)

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

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

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

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

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

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

When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a
line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a6, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.

It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

**High Impact Rating (H)**
This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, BAS, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.
The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of BasBAs with significant impact are covered under this criterion.

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

**Medium Impact Rating (M)**

**Generation**

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

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

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

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

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

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

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

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

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

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

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

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
• Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

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

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

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

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

• Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  ▪ Excluded radial facilities that would only provide support for single generation facilities.
Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

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

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

- 230 kV → 700 MVA
- 345 kV → 1,300 MVA
- 500 kV → 2,000 MVA
- 765 kV → 3,000 MVA

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

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the “fence” of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.

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

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.
Criterion 2.5’s qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. There is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.

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

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

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

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

- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
• Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term “Each” to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

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

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

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

• Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at associated with Control Centers and backup Control Centers, including associated data centers performing the functional obligations of a that monitor and control BES Transmission OperatorLines with an aggregate weighted value of 6000 or higher, and that have not already been included in Part 1. The drafting team included additional qualifications in this criterion that would ensure the required level of impact to the BES is defined and a risk threshold associated to establish a floor for applicable medium impact BES Cyber Systems.

The total aggregated weighted value is used to account for the impact to the BES. The 6000 aggregate weighted value threshold defined in criterion 2.12 provides a sufficient
differentiation for medium and low impact BES Cyber Systems associated with Control
Centers that monitor and control BES Transmission Lines. SDT analysis of Transmission
Control Centers validated that those facilities that may have significant impact are
categorized at an appropriate level commensurate with the associated risk.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV
  and are monitored and controlled by a Control Center, including associated data
  center(s).
- All BES Transmission Lines, including those that connect to neighboring entities, that are
  monitored and controlled by the Responsible Entity’s Control Center, including
  associated data center(s).
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value
  per line.

Criterion 2.12 Examples:

In example 1 below, a BES Cyber System is associated with a Control Center that monitors
and controls eight BES Transmission Lines. In order to calculate the Control Center’s
aggregate weighted value, the Responsible Entity should reference the table located in
Criterion 2.12 and sum the weighted values for each BES Transmission Line.

Example 1

The weighted value for each BES Transmission Line is detailed in the following table by
voltage classification. The calculation of the weighted values is demonstrated below
and equates to an aggregate weighted value of 6100, which is above the minimum
threshold for the medium impact rating required in Criterion 2.12. In accordance with
Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
<th>Applicable Lines</th>
<th>Weighted Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV</td>
<td>(not applicable)</td>
<td>Line 5</td>
<td>N/A</td>
</tr>
<tr>
<td>(not applicable)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
<td>Line 1, Line 2, Line 3, Line 4, Line 7</td>
<td>3500</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
<td>Line 6, Line 8</td>
<td>2600</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
<td>None</td>
<td>0</td>
</tr>
</tbody>
</table>

**Calculation**

700+700+700+700+700+1300+1300 = 6100

In the additional example below, a BES Cyber System is associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center’s aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.
**Example 2**

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2000, which is below the minimum threshold for a medium impact rating required in Criterion 2.12. The BES Cyber System associated with the Control Center in this example should be categorized as high impact. a low impact BES Cyber System pursuant to Criterion 3.1.

<table>
<thead>
<tr>
<th>Voltage Value of a Line</th>
<th>Weight Value per Line</th>
<th>Applicable Lines</th>
<th>Weighted Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>less than 100 kV (not applicable)</td>
<td>(not applicable)</td>
<td>None</td>
<td>N/A</td>
</tr>
<tr>
<td>100 kV to 199 kV</td>
<td>250</td>
<td>Line 1, Line 2, Line 3, Line 4, Line 5, Line 6, Line 7, Line 8</td>
<td>2000</td>
</tr>
<tr>
<td>200 kV to 299 kV</td>
<td>700</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>300 kV to 499 kV</td>
<td>1300</td>
<td>None</td>
<td>0</td>
</tr>
<tr>
<td>500 kV and above</td>
<td>0</td>
<td>None</td>
<td>0</td>
</tr>
</tbody>
</table>
• Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)
BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

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

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

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

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

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

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

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

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator’s Restoration Plan that are components of the Cranking Path.
Use Case: CIP Process Flow

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

Overview (Generation Facility)

- Identify & Categorize BES Cyber Assets and BES Cyber Systems
  - Engineering revisions to reduce impact a BES Cyber System has on a Facility*

- Evaluate BES Cyber Assets and BES Cyber Systems for External Routable Connectivity
  - Engineering revisions to reduce or eliminate External Routable Connectivity*
  - Identify final Electronic Access Points and Electronic Access Control Systems

- Evaluate potential Physical Security Perimeters
  - Engineering revisions to reduce or eliminate physical areas*

- Identify final Physical Security Perimeters and Physical Access Control Systems
  - Apply Security Controls based on applicability

* - Engineering revisions will need to be reviewed for cost justification, operational/safety requirements, support requirements, and technical limitations.
Rationale
During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:
BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:
The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.
Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

i. Control Centers and backup Control Centers;

ii. Transmission stations and substations;

iii. Generation resources;

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

v. Special Protection Systems Remedial Action Schemes that support the reliable operation of the Bulk Electric System; and

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

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

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

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

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

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

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

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

2. Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

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

Responses

Question 1: Whether the phrase “shared BES Cyber Systems,” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states “Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2…” Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states “Each BES Cyber System...associated with any of the following [criteria].” (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that “[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System.” The Background section also provides:

The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.
Question 2: Whether the phrase “shared BES Cyber Systems” refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

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

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

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

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

The phrase applies to each discrete BES Cyber System.
Implementation Plan
Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-002-6

Applicable Standard
- Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization

Requested Retirements
- CIP-002-5.1a - Cyber Security – BES Cyber System Categorization

Prerequisite Standard
These standard(s) or definitions must be approved before the Applicable Standard becomes effective:
- None

Applicable Entities
- Balancing Authority
- Distribution Provider
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date
Reliability Standard CIP-002-6 - Cyber Security – BES Cyber System Categorization
Where approval by an applicable governmental authority is required, Reliability Standard CIP-002-6 shall become effective on 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, Reliability Standard CIP-002-6 shall become effective sixty (60) days following the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.
Planned and Unplanned Changes

Planned changes refer to any changes of the electric system or BES Cyber System as identified through the assessment under CIP-002-6, Requirement R2, which were planned and implemented by the responsible entity.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-6, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the applicable CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

In contrast, unplanned changes refer to any changes of the electric system or BES Cyber System, as identified through the assessment under CIP-002-6, Requirement R2, which were not planned by the responsible entity. Consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-6, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-6, Attachment 1, criteria.

For planned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System, and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems, and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System. For example, initial performance shall be within 15 months following the update of the identification and categorization of the affected BES Cyber System for requirements that must be performed at least once every 15 calendar months.

For unplanned changes resulting in a higher categorization, the responsible entity shall comply with all applicable requirements in the applicable CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems, and Protected Cyber Assets. Initial performance of periodic requirements shall occur by the end of the specified period following the update of the identification and categorization of the affected BES Cyber System.

<table>
<thead>
<tr>
<th>Scenario of Unplanned Changes</th>
<th>Compliance Implementation</th>
</tr>
</thead>
<tbody>
<tr>
<td>New high impact BES Cyber System</td>
<td>12 months</td>
</tr>
<tr>
<td>New medium impact BES Cyber System</td>
<td>12 months</td>
</tr>
<tr>
<td>newly categorized high impact BES Cyber System from medium impact BES Cyber System</td>
<td>12 months for requirements not applicable to medium impact BES Cyber Systems</td>
</tr>
<tr>
<td>Newly categorized medium impact BES Cyber System from low impact BES Cyber System</td>
<td>12 months</td>
</tr>
<tr>
<td>Responsible entity identifies first medium impact or high impact BES Cyber System (i.e., the responsible entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-6 identification and categorization processes)</td>
<td>24 months</td>
</tr>
</tbody>
</table>

For the purposes of transitioning from CIP-002-5.1a to CIP-002-6, increases in BES Cyber System categorization (i.e., from low to medium/high or from medium to high) from the application of CIP-002-6 Attachment 1 criteria are provided 24 months for implementation of applicable CIP Cyber-Security Standards.

**Retirement Date**

**Reliability Standard CIP-002-5.1a**

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-6 in the particular jurisdiction in which the revised standard is becoming effective.
Violation Risk Factor and Violation Severity Level Justifications
Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team’s (SDT’s) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in CIP-002-6. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

**NERC Criteria for Violation Risk Factors**

**High Risk Requirement**
A requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

**Medium Risk Requirement**
A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
**Lower Risk Requirement**
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor and control the BES; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.

**FERC Guidelines for Violation Risk Factors**

**Guideline (1) - Consistency with the Conclusions of the Final Blackout Report**
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the bulk power system. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the bulk power system:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief
Guideline (2) - Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) - Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) - Consistency with NERC’s Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC’s definition of that risk level.

Guideline (5) - Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.
NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple “degrees” of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC’s overarching criteria shown in the table below:

<table>
<thead>
<tr>
<th>Lower VSL</th>
<th>Moderate VSL</th>
<th>High VSL</th>
<th>Severe VSL</th>
</tr>
</thead>
<tbody>
<tr>
<td>The performance or product measured almost meets the full intent of the requirement.</td>
<td>The performance or product measured meets the majority of the intent of the requirement.</td>
<td>The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.</td>
<td>The performance or product measured does not substantively meet the intent of the requirement.</td>
</tr>
</tbody>
</table>

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

**Guideline (1) - Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance**

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

**Guideline (2) - Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties**

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

**Guideline (3) - Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement**

VSLs should not expand on what is required in the requirement.
Guideline (4) - Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

<table>
<thead>
<tr>
<th>Proposed VRF</th>
<th>VRF Justifications for CIP-002-6, Requirement R1</th>
</tr>
</thead>
<tbody>
<tr>
<td>NERC VRF Discussion</td>
<td>A VRF of High was assigned to this requirement. The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 as the basis of a Responsible Entity’s CIP management program.</td>
</tr>
<tr>
<td>FERC VRF G1 Discussion</td>
<td>N/A</td>
</tr>
<tr>
<td>Guideline 1- Consistency with Blackout Report</td>
<td></td>
</tr>
<tr>
<td>FERC VRF G2 Discussion</td>
<td>N/A</td>
</tr>
<tr>
<td>Guideline 2- Consistency within a Reliability Standard</td>
<td></td>
</tr>
<tr>
<td>FERC VRF G3 Discussion</td>
<td>The VRF is not being modified for this requirement. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</td>
</tr>
<tr>
<td>Guideline 3- Consistency among Reliability Standards</td>
<td></td>
</tr>
<tr>
<td>FERC VRF G4 Discussion</td>
<td>The VRF is not being modified for this requirement. A VRF of high is appropriate due to foundational nature of CIP-002-6 in support of a Responsible Entity’s CIP management program. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</td>
</tr>
<tr>
<td>Guideline 4- Consistency with NERC Definitions of VRFs</td>
<td></td>
</tr>
<tr>
<td>FERC VRF G5 Discussion</td>
<td>N/A</td>
</tr>
</tbody>
</table>
### VRF Justifications for CIP-002-6, Requirement R1

<table>
<thead>
<tr>
<th>Proposed VRF</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation</td>
<td></td>
</tr>
</tbody>
</table>

### VSLs for CIP-002-6, Requirement R1

<table>
<thead>
<tr>
<th>Lower</th>
<th>Moderate</th>
<th>High</th>
<th>Severe</th>
</tr>
</thead>
<tbody>
<tr>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems</td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 15 percent of identified BES Cyber Systems</td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</td>
<td>For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems</td>
</tr>
</tbody>
</table>
have not been categorized or have been incorrectly categorized at a lower category; OR
For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 high or medium BES Cyber Systems have not been identified;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 high or medium BES Cyber Systems have not been identified;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 high or medium BES Cyber Systems have not been identified;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;
OR
For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category.
OR
For Responsible Entities with more than a total of 100 high and medium impact and BES Cyber Systems, more than five percent but less than or equal to 10 high or medium BES Cyber Systems have not been identified;
<p>| Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified. | Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified. |</p>
<table>
<thead>
<tr>
<th>FERC VSL G1</th>
<th>The VSL has not been modified for this requirement since there is no change to Requirement R1. The modification is a clarification of Criterion 2.12 of Attachment 1 to CIP-002-6.</th>
</tr>
</thead>
<tbody>
<tr>
<td>FERC VSL G2</td>
<td>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.</td>
</tr>
<tr>
<td>Guideline 2a: The Single Violation Severity Level Assignment Category for &quot;Binary&quot; Requirements Is Not Consistent</td>
<td>Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language</td>
</tr>
<tr>
<td>FERC VSL G3</td>
<td>The VSL has not been modified for this requirement since there is no change to Requirement R1. The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.</td>
</tr>
<tr>
<td>Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement</td>
<td></td>
</tr>
<tr>
<td><strong>FERC VSL G4</strong></td>
<td>The VSL has not been modified for this requirement since there is no change to Requirement R1. The VSLs are based on a single violation, and not cumulative violations.</td>
</tr>
<tr>
<td>-----------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Violation Severity Level</td>
<td>Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations</td>
</tr>
</tbody>
</table>
**PRC-023-4 Implementation Plan Errata**

**Action**
Accept the errata changes to the Implementation Plan for the Revised Definition of “Remedial Action Scheme.”

**Background**
Section 12.0 of the Standard Processes Manual 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.”

Project 2010-05.2 – Special Protection Systems revised the definition of “Remedial Action Scheme” (RAS) in Glossary of Terms Used in NERC Reliability Standards and replaced the term “Special Protection System” with RAS in 29 Reliability Standards, including PRC-023-4 Transmission Relay Loadability. The Implementation Plan for the revised definition of RAS was written specifically for the RAS definition and inadvertently did not carry forward certain necessary implementation provisions found in the Implementation Plan associated with PRC-023-3. Specifically, the RAS Implementation Plan associated with Reliability Standard PRC-023-4 did not contain the implementation provision for load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6. The provision allows each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R1, R2, and R3 to become compliant the latter of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date.

The RAS Implementation Plan also inadvertently omitted information regarding the retirement of Requirement R1, Criterion 6, contained in PRC-023-2 that was included in Implementation Plan of PRC-023-3, but not carried forward to PRC-023-4. The technical basis for Criterion 6 was removed from PRC-023-3 and moved to PRC-025-1 – Generator Relay Loadability; however, Criterion 6 must remain in effect through the implementation of PRC-025-1.
Summary
If the PRC-023-3 implementation plan provision for Requirement R6 is not carried forward, each Transmission Owner, Generator Owner, and Distribution Provider would not have a defined implementation period for which to apply loadability settings on load-responsive phase protection systems newly identified circuits in Requirement R6 by the Planning Coordinator.

Similarly, the provisions regarding the retirement of Criterion 6 is necessary to maintain visibility that each Transmission Owner, Generator Owner, and Distribution Provider is complying with Criterion 6 of PRC-023-2 through the implementation of PRC-025-1. This information was provided in PRC-023-3 Implementation Plan, but not in RAS Implementation Plan affecting PRC-023-4.
Implementation Plan for the Revised Definition of “Remedial Action Scheme”
Project 2010-05.2 – Special Protection Systems

Background
The existing Glossary of Terms Used in NERC Reliability Standards definition for “Special Protection System” (“SPS”) or “Remedial Action Scheme” (“RAS”) lacks the specificity necessary to consistently identify what equipment or protection schemes qualify as SPS/RAS across the eight NERC Regions. The existing definition also does not clearly stipulate the characteristics of a SPS/RAS. The actions listed in the definition of SPS, which are incorporated by cross reference (NERC Glossary of Terms) into the definition of RAS, are ambiguous and may unintentionally include equipment whose purpose is not expressly related to preserving System reliability in response to predetermined System conditions. Employing a single term, i.e., RAS, and clarifying its definition will lead to more consistent application of the NERC Reliability Standards related to RAS.

The proposed definition of RAS must be broad to include the variety of System conditions monitored and corrective actions taken by RAS. Because of the diversity of RAS in both action and objective, the practical approach to the definition is to begin with a wide scope and then list specific exclusions. Without the exclusions, equipment and schemes that should not be considered RAS could be subject to the requirements of the RAS-related NERC Reliability Standards. The exclusion list assures that commonly applied protection and control systems are not unintentionally included as RAS.

The Project 2010-05.2 SPS SDT coordinated the development of the RAS definition with the development of PRC-010-1 by the SDT for Project 2008-02 – Undervoltage Load Shedding. The UVLS SDT introduced a new term, UVLS Program, into the Glossary of Terms Used in NERC Reliability Standards to clearly establish applicability of PRC-010-1. The proposed term UVLS Program is defined as: “An automatic load shedding program consisting of distributed relays and controls used to mitigate undervoltage conditions leading to voltage instability, voltage collapse, or Cascading impacting the Bulk Electric System (BES). Centrally controlled undervoltage-based load shedding is not included.”

Note that the proposed definition excludes centrally controlled undervoltage-based load shedding. The UVLS SDT maintains that the design and characteristics of centrally controlled undervoltage-based load shedding are commensurate with RAS (wherein load shedding is the remedial action) and, as such, should be subject to RAS-related Reliability Standards. The Project 2010-05.2 SPS SDT agreed with this assessment and revised the definition of RAS to clarify that it is exclusive of distributed UVLS relays including the newly defined term UVLS Program. Therefore, the definition is inclusive of centrally controlled undervoltage-based load shedding. Collectively, the two definitions will promote consistency in the identification of centrally controlled undervoltage-based load shedding as RAS. The coordination of these revisions is required to maintain coverage of those systems and prevent a reliability gap. As a
result of these revisions, all NERC Reliability Standards that include the term RAS will be applicable to centrally controlled undervoltage-based load shedding upon the effective dates of the revised definitions of RAS and UVLS Program.

**Requested Approvals**
The definition of “Remedial Action Scheme” and the standards are listed below:

The following standards are proposed for approval to align the use of the single defined term RAS. This list is intended to reflect Reliability Standards currently in effect at the time of Project development. In certain cases, a standard listed below for approval may already be retired pursuant to an implementation plan of a successor version by the time the definition of “Remedial Action Scheme” becomes effective in a particular jurisdiction. In these cases, the standard below will not become effective.

<table>
<thead>
<tr>
<th>CIP-002-3(i)</th>
<th>PRC-004-WECC-2</th>
<th>PRC-020-2</th>
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<td>CIP-002-3(i)b</td>
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<td>PRC-021-2</td>
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<td>EOP-004-3</td>
<td>PRC-005-3(ii)</td>
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<td>PRC-013-1</td>
<td>TPL-001-0.1(i)</td>
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<td>PRC-015-1</td>
<td>TPL-003-0(i)b</td>
</tr>
<tr>
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<td>PRC-016-1</td>
<td>TPL-004-0(i)a</td>
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**Requested Retirements**

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<td>PRC-005-3</td>
<td>PRC-023-2</td>
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<tr>
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<td>PRC-006-1</td>
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<td>PRC-012-0</td>
<td>TOP-005-2a</td>
</tr>
<tr>
<td>IRO-005-3.1a</td>
<td>PRC-013-0</td>
<td>TPL-001-0.1</td>
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<td>MOD-029-1a</td>
<td>PRC-014-0</td>
<td>TPL-002-0b</td>
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<td>MOD-030-02</td>
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<td>PRC-001-1.1</td>
<td>PRC-017-0</td>
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1 This Implementation Plan carries forward and incorporates by reference the following two provisions set forth in the Implementation Plan associated with Reliability Standard PRC-023-3 that are specific to load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6: (1) Each Transmission Owner, Generator Owner, and Distribution Provider in Requirements R2 and R3 shall become compliant the later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date; and (2) Requirement R1, Criterion 6 of PRC-023-2 shall remain in force until the effective date of PRC-025-1.
General Considerations
The entity shall modify its processes as necessary to account for the revised definition. The revised definition of RAS clarifies that it is inclusive of centrally controlled undervoltage-based load shedding. Entities may have additional changes to the classification of certain schemes to align them with the revised definition.

This Implementation Plan provides additional time for entities with newly classified RAS to become compliant with the Reliability Standards during the transition to the revised definition.

All aspects of the Implementation Plans for PRC-005-2 and PRC-005-3 will remain applicable to PRC-005-2(ii) and PRC-005-3(ii). These implementation plans are incorporated here by reference.

Prerequisite Approvals
NERC Reliability Standard PRC-010-1 – Undervoltage Load Shedding
Definition of “Undervoltage Load Shedding Program (UVLS Program)” in Project 2008-02 Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The drafting team proposes the following revised definition:

Remedial Action Scheme (RAS)
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and Mvar), tripping load, or reconfiguring a System(s). RAS accomplish objectives such as:

- Meet requirements identified in the NERC Reliability Standards;
- Maintain Bulk Electric System (BES) stability;
- Maintain acceptable BES voltages;
- Maintain acceptable BES power flows;
- Limit the impact of Cascading or extreme events.

The following do not individually constitute a RAS:

a. Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating the faulted Elements
b. Schemes for automatic underfrequency load shedding (UFLS) and automatic undervoltage load shedding (UVLS) comprised of only distributed relays
c. Out-of-step tripping and power swing blocking
d. Automatic reclosing schemes
e. Schemes applied on an Element for non-Fault conditions, such as, but not limited to, generator loss-of-field, transformer top-oil temperature, overvoltage, or overload to protect the Element against damage by removing it from service
f. Controllers that switch or regulate one or more of the following: series or shunt reactive devices, flexible alternating current transmission system (FACTS) devices, phase-shifting transformers, variable-frequency transformers, or tap-changing transformers; and, that are located at and monitor quantities solely at the same station as the Element being switched or regulated

g. FACTS controllers that remotely switch static shunt reactive devices located at other stations to regulate the output of a single FACTS device

h. Schemes or controllers that remotely switch shunt reactors and shunt capacitors for voltage regulation that would otherwise be manually switched

i. Schemes that automatically de-energize a line for a non-Fault operation when one end of the line is open

j. Schemes that provide anti-islanding protection (e.g., protect load from effects of being isolated with generation that may not be capable of maintaining acceptable frequency and voltage)

k. Automatic sequences that proceed when manually initiated solely by a System Operator

l. Modulation of HVdc or FACTS via supplementary controls, such as angle damping or frequency damping applied to damp local or inter-area oscillations

m. Sub-synchronous resonance (SSR) protection schemes that directly detect sub-synchronous quantities (e.g., currents or torsional oscillations)

n. Generator controls such as, but not limited to, automatic generation control (AGC), generation excitation [e.g., automatic voltage regulation (AVR) and power system stabilizers (PSS)], fast valving, and speed governing

Conforming Changes to Other Standards

The existing Reliability Standards proposed for retirement contain references to SPS or RAS or both. The revised Reliability Standards will reflect the use of the single term RAS. The revised Reliability Standards noted above for approval are included in a separate document Revised Reliability Standards for the Revised Definition of “Remedial Action Scheme.”

Effective Date for Revised Reliability Standards and Definition

Except as noted below, the revised Reliability Standards and the revised definition of “Remedial Action Scheme” shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standards and definition are 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 standards and the definition shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standards and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Implementation Plan for Newly Classified Remedial Action Schemes (RAS)

Entities with newly classified “Remedial Action Scheme” (RAS) resulting from the application of the revised definition must be fully compliant with all Reliability Standards applicable RAS twenty-four (24)
months from the Effective Date of the revised definition of RAS. This additional time applies only to existing schemes that must transition to RAS due to the revised definition. The additional time does not apply to future RAS that may be created following implementation of the revised definition.
Retirement of Existing Standards and Definitions
The requested Reliability Standards for retirement shall be retired at midnight of the day immediately prior to the Effective Date of its successor standard in the particular jurisdiction in which the revised definition is becoming effective. The current definition of “Remedial Action Scheme” shall be retired at midnight of the day immediately prior to the Effective Date of the revised definition of “Remedial Action Scheme”.
Request for Interpretation of FAC-002-2

Action
Reject the Request for Interpretation (RFI) of FAC-002-2 submitted by Southwest Power Pool (SPP) and provide a written explanation for the rejection to the submitter within 10 business days of the decision.

Background
Pursuant to Section 7.0 of the Standard Processes Manual, NERC staff recommends that the RFI be rejected on the grounds that the question has already been addressed in the record.

Section 7.0 of the Standard Processes Manual 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 Standards Committee (SC) is authorized to reject an RFI. Reasons for rejecting an RFI include “[w]here a question has already been addressed in the record.”¹ In this instance, the clarification SPP seeks is unnecessary as the record of development addresses the question.

The RFI submitted by SPP requests clarification of FAC-002-2 Requirement R1. Requirement R1 specifies that “Each Transmission Planner and each Planning Coordinator shall study the impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities.” SPP seeks clarification that FAC-002-2 Requirement R1 does not require duplicate studies of the same interconnecting facilities by both entities if they agree to use one study.

The record of development for FAC-002-1 and FAC-002-2 squarely addresses this issue, providing support for the understanding that the requirement allows for one study to be performed, provided that all parties have an opportunity to participate. The record also provides that the manner in which entities determine to participate and complete the study are organizational decisions best left to the entities to collaborate among themselves.

Specifically, in developing FAC-002-2, the Project 2010-02 standard drafting team (SDT) specified in their finalized Consideration of Issues and Directives Document, which was posted during development and included as supporting material for the filing to Applicable Government Authorities for approval of FAC-002-2, that “[...] only one set of studies may be necessary, and in that case all entities could simply participate and sign on to the same set of studies, but in other cases, multiple sets of studies might be conducted and later coordinated.” (Italics added.)

That clarification was in response to the SDT’s consideration of paragraphs 683 and 687 of FERC Order No. 693. Those paragraphs provide additional supporting emphasis to this understanding. As described in paragraph 683 of Order No. 693, commenters requested that “the Commission clarify that only one required assessment needs to be done when new facilities are added, and that all the listed entities should participate in that single assessment.” In paragraph 687, the Commission stated:

The Commission believes that commenters have raised valid concerns that, if addressed, would make the Reliability Standard better. The wording would allow a number of organizational approaches to achieving the goal of performing an analysis. The Commission does not intend to limit which organizational approach is used by the entities, only to assure that a single competent and collaborative analysis is performed. Therefore, the Commission directs the ERO to address these concerns in the Reliability Standards development process. (Italics added.)

The SDT directly addressed this notion of providing organizational flexibility and supporting the use of one study when they discussed the Reliability Standard’s continued use of “and” in the requirement during their Consideration of Comments posted on June 12, 2014. This Consideration of Comments was in response to the initial ballot of proposed FAC-002-2, which proceeded directly to Final Ballot on June 12, 2014. In their Consideration of Comments, the SDT noted the following:

Several commenters asked the SDT to resolve the Planning Coordinator/Transmission Planner “and” versus “or” terminology among R1, the other requirements, and the Measures and VSLs. One commenter asked for clarification of who leads the study when the Transmission Planner and Planning Coordinator are not the same. The SDT intentionally maintained “and” in R1: “Each Transmission Planner and each Planning Coordinator.” This wording gives the Transmission Planner and the Planning Coordinator the flexibility to determine which entity will study the reliability impact, while 1.4 addresses the option for the entities to jointly study the reliability impact. Once the Transmission Planner and the Planning Coordinator have determined which entity will study the reliability impact, the other Applicable entities will coordinate and

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For the reasons stated above, NERC staff recommends that the SC reject the RFI.

Under Section 7.0, if the SC rejects the RFI, the committee 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 request, the NERC Standards staff shall (i) form a ballot pool and (ii) assemble an Interpretation drafting team with the relevant expertise to address the interpretation for approval by the SC.

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Note: an Interpretation cannot be used to change a standard.

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<th>Interpretation 2010-xx: Request for an Interpretation of [Insert Standard Number], Requirement Rx, for [Insert Name of Company]</th>
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<tbody>
<tr>
<td><strong>Date submitted:</strong></td>
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<tr>
<td><strong>Contact information for person requesting the interpretation:</strong></td>
</tr>
<tr>
<td>Name: Charlton Hill</td>
</tr>
<tr>
<td>Organization: Southwest Power Pool</td>
</tr>
<tr>
<td>Telephone: 501-688-1716</td>
</tr>
<tr>
<td>Email: <a href="mailto:chill@spp.org">chill@spp.org</a></td>
</tr>
<tr>
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</tr>
<tr>
<td>Standard Number (include version number): FAC-002-2</td>
</tr>
<tr>
<td>(example: PRC-001-1)</td>
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<tr>
<td>Standard Title: Facility Interconnection Studies</td>
</tr>
<tr>
<td><strong>Identify specifically what requirement needs clarification:</strong></td>
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<tr>
<td>Requirement Number and Text of Requirement:</td>
</tr>
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<td>R1. Each Transmission Planner and each Planning Coordinator shall study the impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities.</td>
</tr>
<tr>
<td>Clarification needed: When new facilities are added, can the Transmission Planner perform the required study and receive approval from the Planning Coordinator? Would this approach satisfy the requirements for the Planning Coordinator?</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>The standard reads as if the Transmission Planner and the Planning Coordinator have to perform duplicate studies of the same interconnecting facilities. In most cases, this creates duplicate work for the TP and PC staffs and it costs more money for the Transmission Customers who request the new facilities. There may be cases where the Planning Coordinator will need to perform further studies due to other interconnection requests unknown by the respective Transmission Planner.</td>
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When completed, email this form to: sarcomm@nerc.com
## Version History

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2018-2020 Reliability Standards Development Plan

Action
Endorse the 2018-2020 Reliability Standards Development Plan (RSDP).

Background
The draft 2018-2020 RSDP focuses on periodic reviews, Federal Energy Regulatory Commission directives, emerging risks, Standard Authorization Requests, and the standards grading initiative. The RSDP also includes time frames and anticipated resources for each project under development, and considerations for cost effectiveness. NERC and the Standards Committee will continue to work with NERC committees and task forces to bridge any potential reliability gaps and risks.

A draft RSDP was circulated for Standards Committee comment from May 15-22, 2017. The majority of comments received were incorporated in the 2018-2020 RSDP. Significant additions since the comment period include new language on addressing reliability risks and a new discussion on Reliability Standards efficiency review. The latter initiative is based on the material NERC provided to the NERC Standards Oversight and Technology Committee during its August 3, 2017 meeting. Industry comments that did not prompt changes in the draft RSDP will be considered in the 2019-2021 RSDP.

The industry comment period was conducted from June 26-July 25, 2017. The RSDP will be presented to the NERC Board of Trustees in November 2017.
DRAFT Reliability Standards Development Plan

2018-2020

September 2017
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Background

The 2017–2019 Reliability Standards Development Plan (RSDP) continued progress toward NERC’s goal to develop a stable set of clear, concise, technically sound, and results-based NERC Reliability Standards and to retire requirements that do little to promote reliability. The 2017-2019 RSDP specifically highlighted the importance of the Integration of Variable Generation Task Force and Essential Reliability Services Working Group recommendations and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2017-2019 RSDP also indicated that most of the work in the next three years would focus on Periodic Reviews and recognized there may be new or emerging risks identified that would generate new standards development projects. The addition of the Standards Grading Metric in 2016 informs the Periodic Reviews as to the quality and content of the standards.¹

The 2017-2019 RSDP also recognized the importance of addressing subsequent directives from applicable regulatory authorities including the Federal Energy Regulatory Commission (FERC), Standard Authorization Requests (SARs), and the value of enhanced communication through industry feedback loops. It also stressed that Periodic Reviews and standards development activities would occur at a measured pace, compared to the level of activity and pace of standards development during previous years, and they will be aligned with strategic considerations of reviewing standard families that are interrelated.²

As described herein, the 2018-2020 RSDP builds upon the goals of the 2017-2019 RSDP, adding an additional objective of enhanced consideration of cost effectiveness in standards development.

Pursuant to section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year’s RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

¹ The Periodic Review Standing Review Team will grade the standards. The team includes representatives from NERC, the Regional Entities, and the NERC technical committees. Grading occurs prior to conducting the Periodic Review.
² In some cases a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.
Executive Summary

The 2018–2020 RSDP recognizes the diligent work of the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting its focus to Periodic Reviews, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2018-2020 RSDP also contemplates that the work of the various NERC technical committees and working groups thereunder may result in one or more SARs and subsequent standards projects.

As with the 2017-2019 RSDP, Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with strategic considerations of reviewing standard families that are interrelated. The Standards Grading Metric and “Final Grades for Standards Graded in 2017” (Attachment 1) help to inform the Periodic Reviews as to the quality and content of the standards.3

The 2018-2020 RSDP also includes plans for completing the Periodic Reviews initiated in 2016 and 2017, and for commencing additional Periodic Reviews in 2018.

While most of the work in the next three years will focus on Periodic Reviews, there may be new or emerging risks identified that would generate new standards development projects. NERC will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to Bulk Electric System (BES) reliability that may require revisions to existing standards or new standards development. To help determine impact of potential risk to BES reliability, NERC will use various feedback mechanisms, including but not limited to, feedback from the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis, and Compliance violation statistics, as well as any published “Lessons Learned.” The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Standards input will continue to be coordinated with the North American Energy Standards Board as appropriate.

In assessing feedback to create new or revised standards, NERC will focus on risk, reliability or security data, and enforcement information to determine whether a standard revision is the best tool to initially address the reliability risk. Periodic reviews and initiatives such as the streamlining NERC Reliability Standards project also enable NERC to identify requirements that do little to promote reliability and should therefore be retired.

NERC is committed to enhancing and refining cost effectiveness considerations in the standards development process during the 2018-2020 period. For example, during 2016 and 2017, NERC conducted two cost effectiveness pilots.4 NERC continues to develop and implement its cost effectiveness process, which has been implemented more broadly in standards development and will continue to evolve during this work plan period. Cost effectiveness questions are also part of the Periodic Reviews and SAR process. NERC will continue to look for ways to enhance or refine the review and implementation of cost effectiveness during the standards development process in a way that is productive and does not unduly burden the industry for data and input.

This 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication, so that stakeholders may make available appropriate resources to accomplish these standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may

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3 The Periodic Review standing review team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regions, and NERC technical committees. If there is a recommended change in the standard due to Periodic Review recommendations and subject to the standards development process, the Periodic Review standing review team will re-grade the standard with the revised language.

4 Information on NERC’s cost effectiveness initiative can be found at: http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx.
impact the plan. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.
2017 Progress Report

Pursuant to section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development in 2017.

FERC Directives
As of June 30, 2017, there are 29 outstanding FERC directives, 13 of which are related to standards and being resolved through standards development activities. Additionally, FERC has issued directives pertaining to issues outside of NERC standards. These additional directives are being addressed by the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), which are not reflected in this total.

Projects Completed in 2017
The 2017–2019 RSDP identified nine projects initiated in 2017 or continued from 2016. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2017 except for Project 2013-03 Geomagnetic Disturbance Mitigation, Project 2015-09 Establish and Communicate System Operating Limits, Project 2015-10 Single Points of Failure, and Project 2016-02 Modifications to CIP Standards. Additional project information is available on the NERC website on the Standards web page.5

The following projects have been or are planned to be completed in 2017 (actual and anticipated NERC Board of Trustees (Board) adoption dates are noted):

Projects from the 2017-2019 RSDP

2. Project 2016-01 Modifications to TOP and IRO Standards – TOP-001, IRO-002 (adopted by the Board in February 2017)
5. Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001 and VAR-002

5 As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.
2018 Projects

Projects Continuing from 2017 into 2018
In determining high, medium, or low priority to designate projects as listed in this RSDP, the following factors were taken into consideration.

1. Outstanding regulatory directives with filing deadlines (High Priority)
2. RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
3. Potential reliability risk from stakeholders provided through feedback mechanisms (High, Medium, or Low Priority, based on the risk)
4. Outstanding regulatory directives without regulatory deadlines or “soft directives” such as considerations (High or Medium Priority)
5. Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
6. Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

High Priority

• Project 2013-03 Geomagnetic Disturbance Mitigation - TPL-007-2 (drafting estimated to be completed by April 1, 2018 requiring approximately 11 industry subject matter experts for approximately 120 work hours each for the remaining part of this project)
  ▪ FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018
• Project 2016-02 Modifications to CIP Standards (drafting estimated to be completed by May 1, 2018 requiring approximately 10 industry subject matter experts or approximately 75 work hours each for the remaining part of this project)

Medium Priority

• Project 2015-09 Establish and Communicate System Operating Limits- FAC-010, FAC-011, FAC-014 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 100 work hours each for the remaining part of this project)
• Project 2015-10 Single Points of Failure - TPL-001 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 60 work hours each for the remaining part of this project)
• Project 2016-04 Modifications to PRC-025-1 (drafting estimated to be completed by April 1, 2018 requiring approximately 6 industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Low Priority

• Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004 (drafting estimated to be completed by April 1, 2018

---

6 The “estimated drafting completed by” date is NERC’s estimate of the final ballot date.
7 The “work hours” estimates apply to 2018 only.
2018 Projects

Projects Commencing in 2018
At least two Periodic Reviews should commence in 2018 based on feedback from industry and results of the Standards Grading project and other initiatives. Additionally, SARs, emerging risks to the Bulk-Power System, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects in 2018.

NERC Reliability Standards Efficiency Review
As part of its continuing focus on supporting the success and evolution of NERC Reliability Standards to ensure they appropriately address risks to the Bulk-Power System, NERC is interested in assessing where it may be able to realize efficiencies in particular Reliability Standards or requirements through retirement or modification that may no longer be necessary. Beginning in the third quarter of 2017, NERC will begin using internal ERO Enterprise resources, potentially augmented with external expert resources, to evaluate an initial potential scope of an effort to evaluate candidates for such review. Based on that initial review, NERC will solicit industry participants to evaluate possible candidate requirements that may no longer be necessary to support reliability or address current risks to the Bulk-Power System. Through open and transparent industry participation, this list will be formed and vetted with industry in similar fashion as prior efforts to retire requirements that were administrative in nature (e.g., the “Paragraph 81” effort). Lessons from both the “Paragraph 81” effort and the Independent Expert Review Panel underscore the importance of moving forward through open discussion and open solicitation for participants. NERC will also coordinate with the industry team to ensure all of the information developed through the 2016 and 2017 Standards Grading efforts, which includes consideration of content, quality, cost, and reliability impact analysis.

requiring approximately 10 industry subject matter experts for approximately 40 work hours each for the remaining part of this project)

• Project 2017-03 FAC-008 Periodic Review (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 100 work hours each for the remaining part of this project)

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Standards Grading Metrics

The NERC SC endorsed a grading system for standards as a metric on March 9, 2016. The grading is conducted by the Periodic Review Standing Review Team (PRSRT) as set forth in the Periodic Review process. The PRSRT is comprised of the following:

- SRT chair: SC chair or (or SC chair delegate)
- Operating Committee (OC) chair (or OC chair delegate)
- Planning Committee (PC) chair (or PC chair delegate)
- NERC staff
- Representation from the Regional Entities

The grading metrics include possible scores of 0-3 for quality and 0-13 for content. The set of standards chosen each year for grading, according to the criteria in the above section, will be reviewed and their grading will be used to prioritize and determine the sequence they should enter into the Periodic Review process. At least one industry comment period will take place to allow industry to comment on the grading performed by the PRSRT. The grades, based on the PRSRT and any industry input will be finalized, appended to the RSDP, and used to complete the prioritization each year.
**Attachment 1**

**Final Grades for Standards Graded in 2017**

<table>
<thead>
<tr>
<th>Standard and Requirement</th>
<th>Content Average</th>
<th>Quality Average</th>
</tr>
</thead>
</table>

This section will be populated after final grading and prior to final RSDP publication.
DRAFT Reliability Standards Development Plan

2018-2020

JuneSeptember 2017
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- Final Grades for Standards Graded in 2017............................................................................................................6
Background

The 2017–2019 Reliability Standards Development Plan (RSDP) continued progress toward NERC’s goal to develop a stable set of clear, concise, technically sound, and results-based NERC Reliability Standards and to retire requirements that do little to promote reliability. The 2017-2019 RSDP specifically highlighted the importance of the Integration of Variable Generation Task Force and Essential Reliability Services Working Group (ERSWG) recommendations and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2017-2019 RSDP also indicated that most of the work in the next three years would focus on Periodic Reviews and recognized there may be new or emerging risks identified that would generate new standards development projects. The addition of the Standards Grading Metric in 2016 informs the Periodic Reviews as to the quality and content of the standards.¹

The 2017-2019 RSDP also recognized the importance of addressing subsequent directives from applicable regulatory authorities including the Federal Energy Regulatory Commission (FERC), Standard Authorization Requests (SARs), and the value of enhanced communication through industry feedback loops. It also stressed that Periodic Reviews and standards development activities would occur at a measured pace, compared to the level of activity and pace of standards development during previous years, and they will be aligned with strategic considerations of reviewing standard families that are interrelated.²

As described herein, the 2018-2020 RSDP builds upon the goals of the 2017-2019 RSDP, adding an additional objective of enhanced consideration of cost effectiveness in standards development.

Pursuant to section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year’s RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

¹ The Periodic Review standing review team will grade the standards. The team includes representatives from NERC, the Regional Entities, and the NERC technical committees. Grading occurs prior to conducting the Periodic Review.
² In some cases, a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.
Executive Summary

The 2018–2020 RSDP recognizes the diligent work of the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting its focus to Periodic Reviews, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2018-2020 RSDP also contemplates that the work of the various NERC technical committees and working groups thereunder, may result in one or more SARs and subsequent standards projects.

As with the 2017-2019 RSDP, Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with strategic considerations of reviewing standard families that are interrelated. The Standards Grading Metric and “Final Grades for Standards Graded in 2017” (Attachment 1) help to inform the Periodic Reviews as to the quality and content of the standards.3

The 2018-2020 RSDP also includes plans for completing the Periodic Reviews initiated in 2016 and 2017, and for commencing additional Periodic Reviews in 2018.

While most of the work in the next three years will focus on Periodic Reviews, there may be new or emerging risks identified that would generate new standards development projects. NERC will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to BES reliability that may require revisions to existing standards or new standards development. To help determine impact of potential risk to BES reliability, NERC will use various feedback mechanisms, including but not limited to, feedback from the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis and Compliance violation statistics, as well as any published “Lessons Learned.” The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Standards input will continue to be coordinated with the North American Energy Standards Board as appropriate.

In assessing feedback to create new or revised standards, NERC will focus on risk, reliability or security data, and enforcement information to determine whether a standard revision is the best tool to initially address the reliability risk. Periodic reviews and initiatives such as the streamlining NERC Reliability Standards project also enable NERC to identify requirements that do little to promote reliability and should therefore be retired.

NERC is committed to enhancing and refining cost effectiveness considerations in the standards development process during the 2018-2020 period. For example, during 2016 and 2017, NERC conducted two cost effectiveness pilots.4 NERC continues to develop and implement its cost effectiveness process, which has been implemented more broadly in standards development and will continue to evolve during this work plan period. Cost effectiveness questions are also part of the Periodic Reviews and SAR process. NERC will continue to look for ways to enhance or refine the review and implementation of cost effectiveness during the standards development process in a way that is productive and does not unduly burden the industry for data and input.

This 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication, so that stakeholders may make available appropriate resources to accomplish these standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may impact the plan. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.

3 The Periodic Review standing review team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regions, and NERC technical committees. If there is a recommended change in the standard due to Periodic Review recommendations and subject to the standards development process, the Periodic Review standing review team will re-grade the standard with the revised language.

4 Information on NERC’s cost effectiveness initiative can be found at: http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx.
2017 Progress Report

Pursuant to section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development in 2017.

FERC Directives
As of June 14, 2017, there are 29 outstanding FERC directives, 13 of which are related to standards and being resolved through standards development activities. Additionally, FERC has issued directives pertaining to issues outside of NERC standards. These additional directives are being addressed by the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), which are not reflected in this total.

Projects Completed in 2017
The 2017–2019 RSDP identified nine projects initiated in 2017 or continued from 2016. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2017 except for Project 2013-03 Geomagnetic Disturbance Mitigation, Project 2015-09 Establish and Communicate System Operating Limits, Project 2015-10 Single Points of Failure, and Project 2016-02 Modifications to CIP Standards. Additional project information is available on the NERC website on the Standards web page.5

The following projects have been or are planned to be completed in 2017 (actual and anticipated NERC Board of Trustees (Board) adoption dates are noted):

Projects from the 2017-2019 RSDP

2. Project 2016-01 Modifications to TOP and IRO Standards – TOP-001, IRO-002 (adopted by the Board in February 2017)
5. Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001 and VAR-002

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As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.
# 2018 Projects

## Projects Continuing from 2017 into 2018

In determining high, medium, or low priority to designate projects as listed in this RSDP, the following factors were taken into consideration.

1. Outstanding regulatory directives with filing deadlines (High Priority)
2. RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
3. Potential reliability risk from stakeholders provided through feedback mechanisms (High, Medium, or Low Priority, based on the risk)
4. Outstanding regulatory directives without regulatory deadlines or “soft directives” such as considerations (High or Medium Priority)
5. Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
6. Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

### High Priority

- **Project 2013-03 Geomagnetic Disturbance Mitigation - TPL-007-2** (drafting estimated to be completed by April 1, 2018 requiring approximately 11 industry subject matter experts for approximately 120 work hours each for the remaining part of this project)
  - FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018
- **Project 2016-02: Modifications to CIP Standards** (drafting estimated to be completed by May 1, 2018 requiring approximately 10 industry subject matter experts or approximately 75 work hours each for the remaining part of this project)

### Medium Priority

- **Project 2015-09 Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014** (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 100 work hours each for the remaining part of this project)
- **Project 2015-10 Single Points of Failure - TPL-001** (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 60 work hours each for the remaining part of this project)
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### Low Priority

- **Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004** (drafting estimated to be completed by April 1, 2018)

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**Projects Commencing in 2018**

At least two Periodic Reviews should commence in 2018.

The following 31 standards will be eligible for periodic review based in 2018:

- BAL-005-02b
- BAL-006-2
- CIP-014-2
- FAC-003-4
- FAC-010-3
- FAC-013-2
- IRO-001-4
- IRO-006-5
- IRO-008-2
- IRO-010-2
- IRO-014-3
- IRO-017-1
- MOD-008-1
- MOD-020-0
- MOD-025-2
- MOD-026-1
- MOD-001-1a
- MOD-004-1
- MOD-030-3
- MOD-031-2
- MOD-033-1
- PER-001-1.1(ii)
- PRC-002-2
- PRC-002-1
- PRC-015-1
- PRC-016-1

feedback from industry and results of the Standards Grading project and other initiatives. Additionally, SARs, emerging risks to the Bulk-Power System, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects in 2018.
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</thead>
</table>

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Technical Rationale

**Action**
Endorse three volunteers from the Standards Committee (SC) to work with NERC staff on the implementation of the Technical Rationale policy, and report back to the SC at the October call and December meeting on the progress of implementing the policy.

**Background**
The policy was endorsed by the SC at its June 14, 2017 meeting. The policy includes several implementation details, including the following subjects:

1. **To help the development of Technical Rationale on a going-forward basis, the following considerations 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.

To assist with an orderly and smooth transition of the policy’s implementation, the leadership of the SC is asking for three SC members to volunteer to work with NERC staff and any applicable drafting teams to implement the policy in a manner that works for all involved. SC members interested in participating should contact the SC Chair. If more than three members volunteer, the chair will inquire as to the level of interest of the volunteers and work with those that are interested to narrow the list to three.
<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>
<tbody>
<tr>
<td>1.</td>
<td>Revisions to NERC Standard Processes Manual (SPM)</td>
<td>a. Develop and propose recommendations to the SC for revisions and/or modifications to the SC Charter Section 10 and Section 6 of the Standard Processes Manual (SPM), which will address the coordination and oversight involvements of the NERC technical committees.</td>
<td>July 2015</td>
<td>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 was been provided at the June 14 SC meeting.</td>
</tr>
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<td>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.</td>
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<td></td>
<td>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.</td>
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<tr>
<td></td>
<td>Team Lead: Pete Heidrich</td>
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<td></td>
<td>John Bussman</td>
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<td></td>
<td>Ben Li</td>
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<td></td>
<td>Jennifer Flandermeyer</td>
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<td>Steve Rueckert</td>
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<td>Chris Gowder</td>
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<td>Sean Bodkin</td>
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<td>Linn Oelker</td>
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<tr>
<td></td>
<td>Guy Zito (consulting)</td>
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<td></td>
<td>Lauren Perotti (NERC Legal)</td>
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<td></td>
<td>Sean Cavote (NERC)</td>
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<tr>
<td>Task</td>
<td>General Scope of Task</td>
<td>Task Initiated</td>
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<tr>
<td>2. Review/Revise Periodic Review Assessment Template</td>
<td>Review the current version of the periodic review template and revise it as appropriate</td>
<td>May 2017</td>
<td>September 2017</td>
<td>Scope approved by the SC on June 14. SCPS will review and develop a final draft at its September 6, 2017 meeting, in preparation for presentation to the SC for approval at the October SC call.</td>
</tr>
</tbody>
</table>

**Team Lead: Ruida Shu**

Jennifer Flandermeyer
Laura Anderson
Sean Bodkin
### 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>
<tbody>
<tr>
<td>3. Standing task to review/revise resource documents</td>
<td>Per the resource document matrix and periodic update process approved by the SC, review the current version of all resource documents and update them as necessary.</td>
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<tr>
<td>Documents to be updated in next 6 months:</td>
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<tr>
<td>i. <strong>Standard Drafting Team Scope;</strong></td>
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<tr>
<td>Sub-Team:</td>
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<td></td>
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<tr>
<td>- <strong>John Hagen (lead)</strong></td>
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<tr>
<td>- Jennifer Flandermeyer</td>
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<tr>
<td>- Monica Bales</td>
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<tr>
<td>ii. <strong>NERC Glossary of Terms Used in Reliability Standards Definition Development Procedure;</strong></td>
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<tr>
<td>Sub-Team:</td>
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<tr>
<td>- <strong>Chris Scanlon (lead)</strong></td>
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<tr>
<td>- John Hagen</td>
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<tr>
<td>- Jennifer Flandermeyer</td>
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<tr>
<td>iii. <strong>Reliability Standard Quality Review Form</strong></td>
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<tr>
<td>Sub-Team (TBD)</td>
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<tr>
<td>iv. <strong>Three documents are slated for retirement and one is being revised as part of the SPM revisions project: see email for list to insert.</strong></td>
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<tr>
<td></td>
<td>Mar 2017</td>
<td>Sep 2017</td>
<td>Target for SCPS review and endorsement at September 6, 2017 meeting.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>June 2017</td>
<td>Dec 2017</td>
<td>To be reviewed at the September 6, 2017 SCPS meeting.</td>
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<tr>
<td></td>
<td>TBD</td>
<td>Mar 2018</td>
<td>Sub-team being formed. Plan to have an initial draft by the December SCPS meeting.</td>
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<tr>
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<td></td>
<td>Documents to be retired after SPM is revised (cont’d):</td>
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<td></td>
<td></td>
<td></td>
<td>- Approving a Field Test Associated with a Reliability Standard;</td>
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<tr>
<td>Task</td>
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</tbody>
</table>
| 3. Standing task to review/revise resource documents (cont’d) | | | | Documents to be retired after SPM is revised (cont’d):  
- Procedure document: Approving the Posting of Reliability Standard Supporting References;  
- Procedure document: Processing Requests for an Interpretation;  
Document to be updated in conjunction with SPM changes:  
- Guideline document: Guidelines for Interpretation Drafting Teams. |
NERC Legal and Regulatory Update  
July 1, 2017 – August 23, 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>
</tr>
</thead>
</table>
| RD17-7-000      | Petition of the NERC for Approval of Errata to Voltage and Reactive Control Reliability Standards  
NERC submitted errata to Reliability Standards: VAR-001-4.1 (Voltage and Reactive Control), VAR-002-4 (Generator Operation for Maintaining Network Schedules), and VAR-501-WECC-3 (Power System Stabilizer) for Commission Approval. | 8/18/2017           |
| RD16-7-000      | Revisions to the Violation Risk Factors for Reliability Standard BAL-002-2  
NERC submitted proposed revisions to Violation Risk Factors for Requirements R1 and R2 of Reliability Standard BAL-002-2 (Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event) in response to commission directive in Order No. 835. | 8/14/2017           |

FERC ISSUANCES SINCE LAST SC UPDATE

<table>
<thead>
<tr>
<th>FERC Docket No.</th>
<th>Issuance Description</th>
<th>FERC Issuance Date</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>None</td>
<td></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>None</td>
<td></td>
</tr>
</tbody>
</table>
2018-2019 Standards Committee Member Elections

**Action**
For information only.

**Background**
There are members representing ten segments whose term will conclude at the end of December 2017. Therefore, an election will be held to fill the two-year terms (2018-2019) for each of the ten segments, in addition to filling the vacancies for the Segment 3 and Segment 7 2017-2018 terms. Please see Table 1 below for the ten members whose terms will conclude.

According to the *Procedures for Election of Members of the Standards Committee*, Appendix 3B to the NERC Rules of Procedure, nominations will be requested approximately 90 days prior to the start of a new term to fill Standards Committee positions that will become open with the expiration of the current term. Membership terms will start on January 1, 2018.

NERC will announce and publish a notice of the nominations process for segment representatives on or about September 11, 2017, with a nomination period of 21 days and an election conducted in accordance with Appendix 3B to the Rules of Procedure.

To be eligible for nomination, a nominee shall be an employee or agent of an entity registered in the applicable Segment. To allow verification of affiliation, a nominee shall be a registered user in the NERC Registered Ballot Body. It is not required that the nominee be the same person as the entity’s Registered Ballot Body representative for that Segment.

<table>
<thead>
<tr>
<th>Segment</th>
<th>Representative</th>
<th>Title</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Laura Lee</td>
<td>Manager of ERO Support and Event Analysis, System Operations</td>
<td>Duke Energy</td>
</tr>
<tr>
<td>2</td>
<td>Ben Li</td>
<td>Consultant</td>
<td>Independent Electric System Operator</td>
</tr>
<tr>
<td>3</td>
<td>Scott Miller</td>
<td>Manager Regulatory Policy</td>
<td>MEAG Power</td>
</tr>
<tr>
<td>3</td>
<td>Vacant for 2017-2018 term</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Chris Gowder</td>
<td>Regulatory Compliance Manager</td>
<td>Florida Municipal Power Agency</td>
</tr>
<tr>
<td>5</td>
<td>Randy Crissman</td>
<td>Vice President – Technical Compliance</td>
<td>New York Power Authority</td>
</tr>
<tr>
<td>6</td>
<td>Andy Gallo</td>
<td>Director, Reliability Compliance</td>
<td>City of Austin dba Austin Energy</td>
</tr>
<tr>
<td>7</td>
<td>Frank McElvain</td>
<td>Senior Manager, Consulting</td>
<td>Siemens Power Technologies International</td>
</tr>
<tr>
<td>7</td>
<td>Vacant for 2017-2018 term</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Name</td>
<td>Position</td>
<td>Organization</td>
</tr>
<tr>
<td>---</td>
<td>---------------</td>
<td>---------------------------</td>
<td>-------------------------------------------------</td>
</tr>
<tr>
<td>8</td>
<td>Robert Blohm</td>
<td>Managing Director</td>
<td>Keen Resources Ltd.</td>
</tr>
<tr>
<td>9</td>
<td>Alexander Vedvik</td>
<td>Senior Electrical Engineer</td>
<td>Public Service Commission of Wisconsin</td>
</tr>
<tr>
<td>10</td>
<td>Guy Zito</td>
<td>Assistant Vice President of Standards</td>
<td>Northeast Power Coordinating Council</td>
</tr>
</tbody>
</table>
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.
<table>
<thead>
<tr>
<th>Segment and Term</th>
<th>Representative</th>
<th>Organization</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chair 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>Vice-Chair 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>Segment 1-2016-17</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>Segment 1-2017-18</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>Segment 2-2016-17</td>
<td>Ben Li</td>
<td>Independent Electric System Operator</td>
</tr>
<tr>
<td></td>
<td>Consultant</td>
<td></td>
</tr>
<tr>
<td>Segment 2-2017-18</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>Segment 3-2016-17</td>
<td>Scott Miller</td>
<td>MEAG Power</td>
</tr>
<tr>
<td></td>
<td>Manager Regulatory Policy</td>
<td></td>
</tr>
<tr>
<td>Segment 3-2017-18</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>Segment 4-2016-17</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>Segment 4-2017-18</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>Segment 5-2016-17</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>Segment 5-2017-18</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>Name</td>
<td>Title/Role</td>
</tr>
<tr>
<td>-----------</td>
<td>-----------------------------</td>
<td>--------------------------------------------------------</td>
</tr>
<tr>
<td>6-2016-17</td>
<td>Andrew Gallo</td>
<td>Director, Reliability Compliance</td>
</tr>
<tr>
<td>7-2016-17</td>
<td>Frank McElvain</td>
<td>Senior Manager, Consulting</td>
</tr>
<tr>
<td>7-2017-18</td>
<td>vacant</td>
<td></td>
</tr>
<tr>
<td>8-2016-17</td>
<td>Robert Blohm,</td>
<td>Managing Director</td>
</tr>
<tr>
<td></td>
<td>David Kiguel</td>
<td></td>
</tr>
<tr>
<td>9-2016-17</td>
<td>Alexander Vedvik</td>
<td>Senior Electrical Engineer</td>
</tr>
<tr>
<td>9-2017-18</td>
<td>Michael Marchand</td>
<td>Senior Policy Analyst</td>
</tr>
<tr>
<td>10-2016-17</td>
<td>Guy Zito</td>
<td>Assistant Vice President of Standards</td>
</tr>
<tr>
<td>10-2017-18</td>
<td>Steve Rueckert</td>
<td>Director of Standards</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.