UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. _________**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD
TPL-001-5

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard TPL-001-5 – Transmission System Planning Performance Requirements. As discussed more fully herein, proposed Reliability Standard TPL-001-5 improves upon currently effective Reliability Standard TPL-001-4 by providing for more comprehensive and robust planning studies, thereby improving reliability. Further, the proposed standard addresses certain Commission directives from its Order No. 786 approving TPL-001-4.[4] NERC requests that the Commission approve the proposed Reliability Standard (**Exhibit A**) and find that the proposed standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests that the Commission approve: (i) the associated Implementation Plan (**Exhibit B**); (ii) the associated Violation Risk Factors ("VRFs") and

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[1] 16 U.S.C. § 824o (2018).

[2] 18 C.F.R. § 39.5 (2018).

[3] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006), *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] *Transmission Planning Reliability Standards*, Order No. 786, 145 FERC ¶ 61,051 (2013).

Violation Severity Levels ("VSLs"), which remain unchanged from TPL-001-4 (**Exhibit D**); and (iii) the retirement of currently effective Reliability Standard TPL-001-4.

As required by Section 39.5(a)[5] of the Commission's regulations, this Petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**), and a summary of the standard development history (**Exhibit G**). The proposed Reliability Standard was adopted by the NERC Board of Trustees on November 7, 2018.

This Petition is organized as follows: Section I of the Petition presents a summary of the proposed Reliability Standard. Section II of the Petition provides the individuals to whom notices and communications related to the filing should be provided. Section III provides background on the regulatory structure governing the Reliability Standards approval process. This section also provides information on the development of the proposed Reliability Standard through Project 2015-10 – Single Points of Failure TPL-001 and the Commission orders and NERC activities that informed its development. Section IV of the Petition provides a detailed discussion of the proposed Reliability Standard and explains how the proposed standard enhances reliability by providing for more comprehensive consideration of Protection System[7] single points of failure, known outages, and the unavailability of long lead-time equipment in planning studies. Section V of the Petition provides a summary of the proposed implementation plan.

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5 18 C.F.R. § 39.5(a).

6 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

7 Unless otherwise indicated, capitalized terms shall have the meaning set forth in the *Glossary of Terms used in NERC Reliability Standards* ("NERC Glossary"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

I. SUMMARY

The TPL-001 Reliability Standard is one of two Transmission Planning Reliability Standards that set forth Requirements for Planning Authorities and Transmission Planners to develop studies of their portions of the Bulk Electric System ("BES"). The purpose of proposed Reliability Standard TPL-001-5 is to "[e]stablish Transmission system planning performance requirements within the planning horizon to develop a [BES] that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." The proposed standard would require each Planning Authority and Transmission Planner to perform an annual Planning Assessment[8] of its portion of the BES covering a number of System conditions and Contingencies described in the standard.

The proposed standard employs a risk-based approach to the study of Contingencies and the types of corrective action that are required if the entity's System cannot meet the standard's performance requirements. This risk-based approach is carried forward from currently effective Reliability Standard TPL-001-4. For the scenarios considered to be more commonplace ("planning events"), the planning entity must develop a Corrective Action Plan if it determines, through its studies, that its System would experience performance issues. For the scenarios considered to be less commonplace but which could result in potentially severe impacts such as Cascading ("extreme events"), the planning entity must conduct a comprehensive analysis to understand both the potential impacts on its system and the types of actions that could reduce or mitigate those impacts.

As discussed more fully in Section V, proposed Reliability Standard TPL-001-5 improves upon the currently effective standard by enhancing Requirements for the study of Protection

[8] "Planning Assessment" is defined in the NERC Glossary as a "documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

System single points of failure. In this context, a Protection System "single point of failure" refers to a non-redundant component of a Protection System that, if it failed, would affect Normal Clearing[9] of faults. NERC identified this issue as a reliability risk to be addressed based on its analysis of potential single points of failure on the BES using data obtained pursuant to a request for data under Section 1600 of the NERC Rules of Procedure. The proposed standard contains revisions to both the Table 1 planning event (Category P5) and extreme events (Stability 2.a-h) and the associated footnote 13 to provide for more comprehensive study of the potential impacts of Protection System single points of failure. Planning entities would be required to take action, consistent with currently effective TPL-001 Requirements, to address System performance issues identified as a result of these studies.

Additionally, the proposed standard addresses two Commission directives from Order No. 786.[10] First, the proposed standard provides for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies. The modifications reflected in proposed TPL-001-5 address the Commission's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied.[11] Second, the proposed standard modifies Requirements for Stability analysis to require an entity to assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy.[12]

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9 "Normal Clearing" is defined in the NERC Glossary as "a protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

10 *See* Order No. 786 at PP 40, 89.

11 *See id.* at PP 41-45.

12 *See id.* at P 89 (directing NERC to consider such a revision upon the next review cycle of TPL-001-4).

Collectively, these revisions would help improve the quality and rigor of Planning Assessments, thereby contributing to a more reliable Bulk-Power System ("BPS"). The proposed standard also contains an update and a limited number of editorial revisions which improve the readability and organization of the standard.

As discussed more fully in Section V, NERC's proposed phased implementation plan strikes an appropriate balance between implementing the standard in a reasonably expeditious manner and allowing entities sufficient time to come into compliance. The proposed implementation plan recognizes the significant coordination and work that would need to be done to identify, study, and address potential Protection System single points of failure issues. Under the proposed plan, the proposed standard would become effective 36 months after regulatory approval, with additional time afforded to entities to come into compliance with provisions related to Protection System single point of failure analysis and related Corrective Action Plans.

For these reasons, and as discussed more fully herein, NERC respectfully requests that the Commission approve the proposed Reliability Standard and the related elements effective as proposed by NERC.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[13]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[14] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the BPS, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[15] of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[16] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[17] of the Commission's regulations requires the ERO to file with the Commission for its approval each new Reliability Standard that the ERO proposes should become mandatory and enforceable in

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[13] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

[14] 16 U.S.C. § 824o.

[15] *Id.* § 824o(b)(1).

[16] *Id.* § 824o(d)(5).

[17] 18 C.F.R. § 39.5(a).

the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[18] and Section 39.5(c)[19] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[20] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[21]

In its order certifying NERC as the Commission's ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards,[22] and thus satisfy certain of the criteria for approving Reliability Standards.[23] The development process is open to any person or entity with a legitimate interest in the reliability of the BPS. NERC considers the

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[18] 16 U.S.C. § 824o(d)(2).

[19] 18 C.F.R. § 39.5(c)(1).

[20] Order No. 672, *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[21] The NERC Rules of Procedure are available at http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[22] *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 at P 250 (2006).

[23] Order No. 672 at PP 268, 270.

comments of all stakeholders. Stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

C. 2009 NERC Advisory, Order No. 754, and NERC Activities to Study Single Points of Failure on Protection Systems

On March 30, 2009, NERC issued an advisory report notifying the industry that failure of a single component of a Protection System caused three significant system disturbances in the previous five years.[24] Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the BES were advised to address single points of failure on their Protection Systems, when identified in routine system evaluations, to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events. These entities were also advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address single points of failure.

On September 15, 2011, the Commission issued Order No. 754 approving an interpretation of TPL-002-0 Requirement R1.3.10.[25] In this Order, the Commission stated that it believed there is "an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems."[26] To address this concern, the Commission directed "Commission staff to meet with NERC and its appropriate subject matter experts to explore the reliability concern, including where it can best

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24 NERC, Industry Advisory, *Protection System Single Point of Failure* (Mar. 20, 2009), https://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf.

25 *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 (2011). Reliability Standard TPL-002-0 was a predecessor to the currently-effective TPL-001-4 standard.

26 *Id.* at P 19.

be addressed, and identify any additional actions necessary to address the matter."[27] FERC also directed NERC to "to make an informational filing…explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."[28]

In March 2012, NERC submitted an informational filing to the Commission summarizing the results of its early work to study the issue.[29] As described more fully in that filing, NERC staff, FERC technical staff, and industry stakeholders attended a technical conference on October 24–25, 2011, the purpose of which was to focus on the Commission's concern regarding assessment of Protection System failures. One outcome of the 2011 technical conference was that NERC would conduct a data collection effort to aid in assessing whether single points of failure in protection systems pose a reliability concern. To that end, the NERC Board of Trustees approved a request for data under Section 1600 of the NERC Rules of Procedure (the "Order No. 754 Data Request") on August 16, 2012.[30]

Over the next two years, NERC collected data from Transmission Planners. Using the collected data, two subcommittees of the NERC Planning Committee, the System Protection and Control Subcommittee ("SPCS") and the System Analysis and Modeling Subcommittee ("SAMS"), conducted an assessment of Protection System single points of failure. The findings

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27 *Id.* at P 20.

28 *Id*.

29 *Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754,* Docket No. RM10-6-000 (Mar. 15, 2012).

30 Request for Data or Information: Order No. 754 Single Point of Failure on Protection Systems (Aug. 16, 2012), http://www.nerc.com/pa/Stand/Pages/order_754.aspx. The process governing Requests for Data or Information is contained in Section 1600 of the NERC Rules of Procedure, http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

were presented in a September 2015 report titled *Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*.[31] In the report, the SPCS and SAMS found that single points of failure on Protection Systems did pose a reliability risk that warranted further action. The report concluded:

> Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists). Not all failures adversely affect reliable operation of the bulk power system. The reliability risk varies based on which component of a protection system fails.[32]

The SPCS and the SAMS recommended, after considering a variety of alternatives to address this reliability concern, that NERC modify Reliability Standard TPL-001-4 through the NERC standards development process. The SPCS and the SAMS concluded that this approach best aligns with FERC Order No. 754 directives and maximizes reliability of Protection System performance. The report recommended that three-phase faults involving Protection System failures be assessed as an extreme event in the TPL-001 standard, as follows:

> Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in

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[31] NERC SPCS/SAMS, *Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* (Sep. 2015) ("SPCS/SAMS Report"), https://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/FERC%20Order%20754%20Final%20Report%20-%20SPCS-SAMS.pdf.

NERC submitted this report to the Commission on an informational basis on October 30, 2015 in Docket No. RM10-6-000. *See Informational Filing of NERC, Assessment of Protection System Single Points of Failure*, Docket No. RM10-6-000 (Oct. 30, 2015).

[32] SPCS/SAMS Report at 11.

> TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: 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.[33]

Following the issuance of this report, NERC initiated a standards development project to consider the specific recommendations from this report. Later, NERC expanded the scope of the project to address two Commission directives from Order No. 786 approving TPL-001-4, as discussed further below.

D. Order No. 786 Approving TPL-001-4

In Order No. 786, the Commission approved the currently effective version of the transmission system planning standard, TPL-001-4. In that Order, the Commission also issued several directives to NERC, including two relating to future standard modifications that are addressed in proposed Reliability Standard TPL-001-5.

First, the Commission expressed concern that the six month outage duration threshold in TPL-001-4 Requirement R1 could exclude planned maintenance outages of significant facilities from future planning assessments. The Commission found that "planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods," and that "[p]rudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load."[34] The Commission further stated, "[a] properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation,

[33] *Id. at* 11; *see also id.* at 9 (discussion of alternatives to address reliability risks).

[34] Order No. 786 at P 41.

transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding."[35] The Commission directed NERC to modify the TPL-001 standard to address this concern.

Second, while stating that NERC had met the Commission's Order No. 693 directive to include a spare equipment strategy for steady state analysis in TPL-001-4, the Commission found that a spare equipment strategy for stability analysis was not addressed in the standard.[36] The Commission stated that it "believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment."[37] Rather than direct a change at that time, however, the Commission directed NERC to consider the issue during the next review cycle of TPL-001-4.[38]

E. Project 2015-10 Single Points of Failure TPL-001

In October 2015, NERC initiated Project 2015-10 Single Points of Failure TPL-001 to address the Protection System single points of failure recommendations from the SPCS/SAMS report. Subsequently, the scope of the project was expanded to add consideration of the Commission's Order No. 786 directives and an update to a MOD standard reference in the TPL-001 standard. In developing the proposed standard, the standard drafting team considered the

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35 *Id.*

36 Order No. 786 at P 88. In Order No. 693, the Commission directed NERC to modify TPL-001-0 "to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy." *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693 at P 1768, FERC Stats. & Regs. ¶ 31,242 (2007) (Order No. 693), *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007). This led to the development of TPL-001-4 Requirement R2, Part 2.1.5 addressing steady-state conditions to determine system response when critical equipment is unavailable for a prolonged period of time.

37 Order No. 786 at P 89.

38 *Id*.

discussion and recommendations of the SPCS/SAMS report on Protection System single points of failure. The standard drafting team also considered additional recommendations developed by the SAMS to address the two Order No. 786 directives,[39] feedback received throughout the standard development process, and its own experience and expertise in the subject matter area.[40]

The proposed standard and implementation plan were posted once for informal comment and three times for formal comment and ballot. The fifth draft of proposed Reliability Standard TPL-001-5 and the associated implementation plan were approved by the ballot body on October 22, 2018. The proposed standard received a 66.69 percent approval rating, with 86.39 percent quorum. The proposed implementation plan received a 72.44 percent approval rating, with 86.73 percent quorum. The NERC Board of Trustees adopted the proposed standard on November 7, 2018. A summary of the development history and the complete record of development is attached to this Petition as Exhibit G.

IV. JUSTIFICATION FOR APPROVAL

As discussed in Exhibit C and below, proposed Reliability Standard TPL-001-5 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The purpose of the proposed standard is to "[e]stablish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliability over a broad spectrum of System conditions and following a wide range of probable Contingencies." As with the purpose

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39 NERC SAMS, *FERC Order 786 Directives* (2016), https://www.nerc.com/comm/PC/System%20Analysis%20and%20Modeling%20Subcommittee%20SAMS%20201/FERC%20Order%20786%20Directives%20-%20SAMS%20White%20Paper%20-%202016-07-22.pdf.

40 The standard drafting team roster for Project 2015-10 Single Points of Failure TPL-001 is attached to this Petition as Exhibit **H**.

statement, the applicability of the proposed standard (Planning Coordinators and Transmission Planners) remains unchanged from the currently effective standard.

Proposed Reliability Standard TPL-001-5 improves upon the currently effective version of the standard by revising the existing Table 1 planning and extreme events to require a more complete, risk-based analysis of how the failure of a non-redundant component of a Protection System would affect a planning entity's System. The proposed standard also improves upon the currently effective standard and addresses the Commission's standard modification directives from Order No. 786 by: (i) requiring a more comprehensive analysis of known outages in planning studies; and (ii) requiring entities to consider, in Stability analysis, the impacts of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy. Lastly, the proposed standard contains an update to a MOD standard reference and editorial revisions to improve organization.

The proposed standard revisions and the justification for each is provided below. The proposed revisions are shown in the TPL-001-5 redline attached to this Petition as Exhibit A.

A. Revisions to Address Studies of Single Points of Failure on Protection Systems

Proposed Reliability Standard TPL-001-5 contains a series of revisions to help ensure that planning entities are: (1) performing a more complete analysis of potential Protection System single point of failure issues on their Systems; and (2) taking appropriate action to address these concerns. The SPCS/SAMS report concluded that "the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action" and that "risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists).”[41] To address this concern, proposed Reliability Standard TPL-001-5 revises:

- the Table 1, Category P5 planning event, which would require the planning entity to study the impact on its System of Delayed Fault Clearing[42] due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed;

- the Table 1, Stability Extreme Events 2.a-2.h, which would require the planning entity to study the impact on its System of a three-phase fault with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing; and

- Table 1, footnote 13, which specifies the Protection System equipment to be considered as part of studying the Category P5 planning event and Stability Extreme Events 2.e-2.h.

Collectively, the proposed revisions help ensure that planning entities are performing a risk-based assessment of the potential impacts of Protection System single points of failure that could pose a risk to reliability. Each of these revisions in the proposed standard is discussed below, beginning with the revisions to Table 1, footnote 13 which specify the non-redundant Protection System components to be considered as part of planning studies.

1. Revisions to Table 1, Footnote 13

Proposed Reliability Standard TPL-001-5 employs a risk-based approach to the study of Protection System single points of failure. Accordingly, proposed Table 1, footnote 13 is intended to focus the planning entity’s consideration on those non-redundant components of a

[41] SPCS/SAMS Report at 11.

[42] “Delayed Fault Clearing” is defined in the NERC Glossary as “Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.”

Protection System that may, when they fail, lead to Delayed Fault Clearing when simulating the Category P5 planning event and Stability extreme events 2.e-h.

In proposed Reliability Standard TPL-001-5, the limited set of relay functions or types in Table 1, Footnote 13 is replaced with an expanded list of components to capture the Protection System single point of failure concern. Guided by the SPCS/SAMS report recommendations, the TPL-001-5 standard drafting team selected a list of components to account for: (1) those failed non-redundant components of a Protection System that may impact one or more Protection Systems; (2) the duration that faults remain energized until Delayed Fault Clearing; and (3) the additional system equipment removed from service following fault clearing depending on the specific failed non-redundant component of a Protection System.[43]

Footnote 13 is revised to list four specific types of non-redundant Protection System components, as follows:

> ~~13. 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).~~
>
> 13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
>
>   a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
>
>   b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
>
>   c. A single station dc supply associated with protective functions required for Normal Clearing (an exception

[43] See Technical Rationale at 4-5. Additional information regarding the selection of each particular component is available in the Technical Rationale on pages 5-10.

is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);

d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

The revised Footnote 13 does not include all Protection System components in the list of potential non-redundant components to consider. The SPCS/SAMS report described failure of voltage or current sensing devices as having a lower level of risk of failure to trip.[44] The reliability risk associated with the failure of these components is lower than the risk posed by the failure of a Protection System component that is needed to clear a fault. Therefore, voltage or current sensing devices are not included in the revised footnote 13. Similarly, control circuitry whose failure does not prevent Normal Clearing of a fault, such as reclosing circuitry and reclosing relays, is not considered under the revised footnote 13.[45]

An explanation for each of the types of devices to be included in Protection System single point of failure studies under revised footnote 13a.-d is provided below.

a) Footnote 13.a – Protective Relays

Footnote 13.a includes among the components to consider "a single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times." Other Requirements address simulation of Protection System action.[46] Footnote 13.a therefore limits the potential

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44 *See* Technical Rationale at 5; *see also* SPCS/SAMS Report at 7.

45 *See* Technical Rationale at 5.

46 *See* TPL-001-5 Requirement R3 Part 3.3.1 and Requirement R4 Part 4.3.1.

single points of failure to study to those single protective relays which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. A single point of failure in such a relay may result in the primary Protection System failing to operate properly, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection.[47] For footnote 13.a, an "alternative that provides comparable Normal Clearing times" refers to a relay that results in fault clearing within the expected Normal Clearing time period and isolates the fault by tripping similar System Elements than if the single protective relay that is simulated to fail were to function properly. By noting that the alternative may or may not respond to electrical quantities, Footnote 13.a accounts for those Protection System designs in which non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities.[48]

b) Footnote 13.b – Communications Systems

Footnote 13.b includes among the Protection System components to consider a "a single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center)." Given the increasing importance of communication-aided Protection Systems, the proper operation of the communication system must be considered when considering potential Protection System components to study for single points of failure concerns. A communication-aided Protection System that may experience a single point of failure, causing it to operate improperly or not at all, must be considered among non-redundant components.

[47] Footnote 13.a does not include backup protective relays given that a single point of failure in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

[48] For an example of such a design, see the Technical Rationale at 5-7.

Footnote 13 provides that certain non-redundant components that are both monitored and reported at a Control Center would not need to be considered as part of planning studies. This includes the communications systems identified in footnote 13.b. The standard drafting team considered that the monitoring and reporting of a non-redundant component to a centralized location (i.e., the Control Center) would facilitate prompt identification and correction of abnormal conditions to minimize the exposure to and consequence of the failed component. Therefore, it concluded that such monitored and reported components exhibited a lower risk, on par with being redundant, than a non-redundant component that reported to a remote location or one whose failure might go undetected for some time.[49]

c) Footnote 13.c – Station DC Supply

Footnote 13.c includes among the Protection System components to consider "a single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit)." Failure of a single station Protection System DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. Similar to footnote 13.b, monitoring and reporting the status of the DC supply to a centralized location can be considered a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure.

d) Footnote 13.d – Control Circuitry

Lastly, footnote 13.d would require consideration of "a single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply

[49] Technical Rationale at 5.

through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).” Failure of a Protection System single control circuitry is a significant point of failure as it will prevent proper tripping and, depending upon its design and mode of failure, may also prevent the initiation of breaker failure protection.[50] Further, most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions, such as multiplexing trip signals for differential or breaker failure initiation. Single control circuitry should be considered a non-redundant component of a Protection System given that Delayed Fault Clearing, including significantly delayed remote end or backup clearing, is expected when the non-redundant auxiliary or lockout relay device within the single control circuitry fails.

The single control circuitry is demarcated from the DC supply through and including the trip coil(s) for the purpose of including all devices in the control circuitry which, if failed, may prevent proper Protection System action leading to Delayed Fault Clearing. Trip coils are commonly employed in pairs for the purpose of incorporating redundancy to actuate the tripping of a circuit breaker or other interrupting device. When a single trip coil is employed, monitoring and reporting the status of the single trip coil to the Control Center can be considered as a sufficient alternative to its physical redundancy given that prompt notification and remediation is expected, which minimizes the risk the trip coil failure. However, all constituent parts of the

[50] Breaker failure is addressed by the Table 1, Category P4 planning event.

single control circuit (including wires) should be included when considering whether the single control circuit may be a non-redundant component of a Protection System.

2. Revisions to the Table 1, Category P5 Planning Event

The Category P5 event in Table 1 of proposed Reliability Standard TPL-001-5 would require the planning entity to simulate a Contingency where a single line-to-ground fault occurs and Delayed Fault Clearing results due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed. Stated differently, the Protection System does not operate as designed to clear the single line-to-ground fault in the time normally expected with proper functioning of the Protection System due to a single point of failure. When a Protection System does not operate as designed or fails to isolate faulted equipment within the time normally expected with its proper functioning, backup protection capabilities must act to clear the fault. Such backup systems are designed with intentional time delays before fault clearing. Additionally, the operation of these backup systems could result in significant differences in final System configuration. For example, more System Elements may be removed from service when the backup Protection System operates than may be expected during primary Protection System operation.

Revisions are proposed to the Category P5 event to be consistent with the revisions to footnote 13, replacing the word “relay” with the more inclusive phrase “component of a Protection System”, as follows:

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~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	SLG	EHV	No[9]	No
				HV	Yes	Yes

Consistent with currently effective Reliability Standard TPL-001-4, the entity would be required to develop a Corrective Action Plan in the event it determines that its System would be unable to meet the performance requirements of Table 1 for the Category P5 event. Corrective action requirements for the revised Protection System single point of failure studies are discussed in Section IV.A.4, below.

3. Revisions to Table 1, Extreme Events, Stability Column Events

Consistent with the recommendations of the SPCS/SAMS report, proposed Reliability Standard TPL-001-5 revises the Table 1 Extreme Events to place additional emphasis on assessment of three-phase faults involving single points of failure on a Protection System. In proposed Reliability Standard TPL-001-5, the extreme events in the Stability column of Table 1 is revised so that four distinct items, 2.e-2.h, would address study of Protection System single points of failure in combination with three-phase faults, as follows:

Table 1, Steady State & Stability Performance Extreme Events

Stability

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2. Local or wide area events affecting the Transmission System such as:

a. 3Ø fault on generator with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.

b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure~~~~[13]~~ resulting in Delayed Fault Clearing.

c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure~~~~[13]~~ resulting in Delayed Fault Clearing.

d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure~~~~[13]~~ resulting in Delayed Fault Clearing.

e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

~~e.~~i. 3Ø internal breaker fault.

~~f.~~j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

As demonstrated above, Table 1, Extreme Events, Stability column, items 2.a. through 2.d are revised to strike the term “relay failure.” Items 2.e through 2.h are added to address specifically the study of a three-phase fault on a generator, Transmission circuit, transformer, or bus section in combination with a failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing. Footnote 13, discussed above, identifies the specific non-redundant components of a Protection System that should be considered as part of these extreme event studies.

As discussed in the following section, proposed Reliability Standard TPL-001-5 carries forward requirements from TPL-001-4 relating to the action the planning entity must take in the event its studies indicate System performance issues for this event.

4. Corrective Action Requirements for the Revised Table 1 Category P5 and Stability Extreme Events Items 2.e-2.h Studies

The proposed TPL-001-5 Reliability Standard, like the currently effective TPL-001-4 standard, takes a risk-based approach to System planning studies. Generally, the standard contains more stringent corrective action requirements for the more commonplace scenarios, and less stringent corrective action requirements for the rarest, but potentially most severe, scenarios. This general framework is based on widely-accepted principles of cost-effective, risk-based planning. As the Commission stated in a prior proceeding, "The Commission agrees that [the extreme event Transmission Planning] Reliability Standard should not require improvements for low probability events that cannot be justified."[51] The planning entity should, however, be required to fully understand the potential impacts such events could have on its System and the steps that could be taken to address those impacts.[52] The planning entity would then use this information to make an informed decision on the best way to plan its System for these rare scenarios. This decision should take into account all relevant considerations. By way of example, those considerations could include the entity's planning priorities, the probability of the event, and the expected impacts of the event. These considerations could also include the interests of its customers and the entity's ability to obtain cost recovery.

Proposed Reliability Standard TPL-001-5 carries forward this risk-based approach to the study of Protection System single points of failure. As discussed in the previous sections, TPL-001-5 replaces "relays" as the equipment to be studied in the Table 1, Category P5 planning

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[51] *See* Notice of Proposed Rulemaking, *Mandatory Reliability Standards for the Bulk-Power System*, 117 FERC ¶ 61,084 (Oct. 20, 2006) at P 1112 (proposing to approve Reliability Standard TPL-004-0 – System Performance Following Extreme BES Events, which is a predecessor to the currently effective TPL-001-4 standard).

[52] *See id.* and Order No. 693 at P 1836 (approving TPL-004-0 and directing NERC to modify the standard to require, among other things, "the identification of options for reducing the probability or impacts of extreme events that cause cascading.")

event and Stability extreme events items 2.e-2.h with a broader list of potentially problematic non-redundant Protection System components. The approach to mitigation for these events remains unchanged from currently effective TPL-001-4.

The single line-to-ground fault scenario described in the revised Category P5 planning event is considered to be the more commonplace scenario involving Protection System single points of failure; therefore, if the planning entity determines that its System is unable to meet the standard's performance requirements, it must develop a Corrective Action Plan to address the deficiencies. Requirement R2.7 in proposed Reliability Standard TPL-001-5 addresses Corrective Action Plan requirements and remains substantively unchanged from the currently effective standard. Such Corrective Action Plans for the Category P5 planning event may include adding redundant components; however, this is only one of many alternatives for corrective actions that planning entities may consider to achieve required System performance.

By contrast, the three phase fault scenario described in the revised Table 1, Extreme Events, Stability column items 2.e-h is considered to be the much rarer occurrence, as discussed further below. Like the other extreme events in the proposed standard, this scenario, while rare, could result in more significant impacts to an entity's System. During the development of the proposed standard, the standard drafting team considered several alternative approaches to the study of Protection System single points of failure with three-phase faults, particularly the type of mitigation action that should be required by the standard. Taking into account all relevant considerations, including industry feedback and the recommendations of the SPCS/SAMS report, the TPL-001-5 drafting team determined that the most appropriate and cost effective approach would be to carry forward the approach of currently effective TPL-001-4. Under this approach, if an entity determines that its System will experience Cascading[53] as a result of a three-phase fault scenario, "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequence(s) of the event shall be conducted." In proposed Reliability Standard TPL-001-5, this Requirement is carried forward in Requirement R4 Part 4.2.[54] The ERO would continue to audit compliance with this analysis provision similarly to how it is audited under the currently effective standard, taking into account the expanded list of Protection System components considered in the study.

The corrective action requirements for the revised single line-to-ground fault and three phase fault scenarios fit within the risk-based framework of the TPL-001 standard. Data collected by NERC since 2011 provides further support that this framework remains appropriate for Protection System single points of failure studies. Like all of the "extreme event" scenarios in this framework, the impacts of a Protection System single point of failure in combination with a three phase fault could be severe in some cases, but are very unlikely. A historical analysis of NERC's data on Protection System misoperations indicates that the expected likelihood of such an event occurring and resulting in the most severe impacts would be small. NERC recently completed a review of over 12,000 Protection System misoperations in its Misoperation Information Data Analysis System ("MIDAS") database reported since 2011.[55] Of the over

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53 Cascading is defined in the NERC Glossary as: "The uncontrolled successive loss of System Elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies."

54 This provision is unchanged from currently-effective TPL-001-4, except that it is moved from Requirement R4 Part 4.5 to Part 4.2 in proposed TPL-001-5 for editorial reasons. Similarly, the provision applicable to steady state extreme events analysis is moved from Requirement R3 Part 3.5 to Part 3.2.

55 The ERO began to collect misoperations data in a common format beginning in 2011. Applicable entities are currently required to report information on Protection System misoperations to NERC pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure approved by the NERC Board of Trustees on August 14, 2014. Previously, the PRC-004 standard contained requirements for misoperation reporting.

12,000 Protection System misoperations in MIDAS, 28 involved three-phase faults. Of that number, only 10 involved breakers that failed to operate (the remaining 18 involved breakers that were slow to operate). Failure to operate potentially indicates instances of a Protection System single point of failure. While the potential for severe impacts from such events remains, none of the 10 failure to trip scenarios reported since 2011 resulted in events that reached the threshold for reporting to NERC under Reliability Standard EOP-004.[56]

For these reasons, it remains appropriate to carry forward the risk-based mitigation approach in currently effective Reliability Standard TPL-001-4 to the revised Protection System single points of failure planning studies in proposed Reliability Standard TPL-001-5.

B. Revisions to Address Order No. 786 Directives

In addition to addressing reliability issues involving single points of failure on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two Commission directives from Order No. 786. Under the first directive, the Commission directed NERC to modify TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.[57] Under the second directive, the Commission directed NERC to consider whether TPL-001-4 should contain a spare equipment strategy for Stability analysis, similar to that for steady state analysis.[58] For steady state analysis, TPL-001-4 Requirement R2 Part 2.1.5 requires studies to be performed for P0, P1, and P2 categories with the conditions that the system is expected to

[56] The EOP-004 Reliability Standard specifies Requirements for entities to report disturbances and events that have the potential to impact the reliability of the BPS.

[57] Order No 786 at P 40.

[58] *Id.* at P 89.

experience during the possible unavailability of the long lead-time equipment. A discussion of the revisions in proposed TPL-001-5 to address these directives is provided below.

1. Study of Known Planned Outages

In proposed Reliability Standard TPL-001-5, NERC made several revisions to address the Commission's concern in Order No. 786 that the six-month threshold in TPL-001-4 Requirement R1 Part 1.1.2 could exclude planned maintenance outages of significant facilities from future planning assessments.[59] The proposed revisions are intended to complement Reliability Standard IRO-017-1, which requires: (1) each Reliability Coordinator to maintain an outage coordination process within its Reliability Coordinator Area; and (2) each Planning Coordinator and Transmission Planner to provide its Planning Assessment to impacted Reliability Coordinators and to jointly develop solutions with its Reliability Coordinator(s) for identified issues or conflicts with planned outages.

The proposed revisions are intended to strengthen the collaboration and consultation between the Reliability Coordinator and the Transmission Planner or Planning Coordinator at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon. In developing a comprehensive approach to the study of known outages in Planning Assessments, and one that is flexible enough to accommodate the various outage coordination processes in use across the North America, the TPL-001-5 standard drafting team considered the Commission's guidance in Order No. 786, the recommendations of the NERC SAMS, feedback received during the standard development process, as well its own experience and subject matter expertise.

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[59] *Id.* at P 40.

In proposed TPL-001-5, the provision relating to the assessment of known outages (Requirement R1 Part 1.1.2) is struck from Requirement R1 and new provisions are added under Requirement R2, Parts 2.1 and 2.4. These new provisions specify how analyses shall be assessed and supported by studies. The relevant revisions to Requirement R2 are shown below:

> **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~~.
>
> *******
>
> <u>**2.1.4.** When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the</u>

Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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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:

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2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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In proposed Reliability Standard TPL-001-5, the six month outage threshold is removed. Planning entities would instead select known outages for study based on a documented procedure or rationale that takes into account relevant factors, but does not exclude known planned outages based solely on the outage duration. The change to where the assessment of known outages is specified in the TPL-001-5 requirements better aligns the approach necessary for the planning entities to execute their annual Planning Assessments. Further, the proposed Requirement language recognizes the various means that Planning Coordinators and Transmission Planners currently employ to consider the maintenance outages that could potentially be of concern.

Under proposed Requirement R2 Parts 2.1.4 and 2.4.4., each Planning Coordinator and Transmission Planner must have either a documented outage coordination procedure or technical rationale to select which known outages shall be assessed as part of the steady state (Requirement R2, Part 2.1.4) and Stability (Requirement R2, Part R2.4.4) analysis. The documented outage coordination procedure would include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes. The technical rationale would include the well-reasoned technical bases for making the determination of which known outages to assess.

Consistent with the intention of Order No. 786, the proposed provisions specify that an entity shall not exclude known outages to be modeled based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be assessed in the Near-Term Transmission Planning Horizon.

Under the proposed standard, an entity would be required to include, at a minimum, those known outages expected to cause more severe System impacts, such as those that may result in Non-Consequential Load Loss for the Table 1 Category P1 event. The Planning Coordinator and Transmission Planner would have flexibility to use the appropriate means to assess which known outages are expected to be significant, and to exclude from the assessment those outages which the Planning Coordinator and Transmission Planner do not expect to be problematic. When selecting those known outages for study, consideration must be paid to the System conditions, such as On-Peak or Off-Peak, that are expected during the period when the known outage is planned. The proposed standard provides that past or current studies may support the selection of one or more known outages, if the past or current study or studies has comparable post-Contingency System conditions and configuration. For example, in many cases the Category P3 and P6 event study could result in the same System state as the Category P1 event with the known outage. Such analysis, therefore, may be useful in helping to select which known outages to study.

2. Spare Equipment Strategy for Stability Analysis

NERC also proposes revisions to address the Commission's Order No. 786 directive to consider adding provisions for spare equipment strategy as part of Stability analysis. In Order No. 786, the Commission noted that TPL-001-4 Requirement R2 Part 2.1.5 requires that steady state studies 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. The Commission stated that it believed that "a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment." The Commission directed NERC to consider the issue upon the next review cycle of TPL-001-4.[60]

[60] Order No. 786 at P 89.

Consistent with the Commission's Order No. 786 guidance, the standard drafting team revised the standard to add a similar requirement for Stability analysis, as follows:

> **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, Part2.6. The following studies are required:
>
> ***
>
> **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.

The addition of Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5,[61] clarifies that the outage of long lead time Elements has an equally important impact from a Stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy. While the language in the two provisions is similar, there are two important differences.

First, the Category P0 event is not included because it is implied in the study. The nature of Stability analysis is to observe the System dynamic response during and after a disturbance. The Category P0 event conditions represent the undisturbed, initial, "normal" state of the System. Given that initial System conditions for each long-lead time Element that is removed from service are identical between steady state and Stability analyses, the Stability analysis of

61 Corresponding editorial changes are proposed in Requirement R2, Part 2.1.5, as shown in Exhibit A.

the P0 event is implicitly assessed when conducting the steady state analysis of the P0 event. Similarly, the prerequisite for conducting the Category P1 and P2 event Stability analysis is a System model that incorporates and is initialized as the undisturbed (P0) state of the System. Therefore, Category P0 is redundant and is appropriately omitted from Requirement R2 Part 2.4.5.

Second, proposed Reliability Standard TPL-001-5 Requirement R2 Part 2.4.5 provides that "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 dynamic response of the System and its ability to meet performance requirements are expected to be more stressed for certain Category P1 and P2 category events, topologically close to where the long-lead time Element is removed from service. Consistent with Requirement R3 Part 3.4, those Category P1 and P2 events expected to produce more severe System impacts are selected for Stability analysis. Additionally, prior testing and knowledge of system performance can help to limit Stability testing to the relevant limiting events.

C. Other Revisions

Proposed Reliability Standard TPL-001-5 also contains several other revisions not specifically highlighted above. First, the reference to the MOD-010 and MOD-012 standard in Requirement R1 is replaced with a reference to the MOD-032 standard, which now contains the relevant Requirements.[62] Second, references to "Special Protection System" have been replaced with "Remedial Action Scheme," consistent with previously-approved revisions to those defined

[62] The Commission approved Reliability Standard MOD-032-1 and the retirement of Reliability Standards MOD-010-0 and MOD-012-0 in 2014. *See N. Am. Elec. Reliability Corp.*, Docket No. RD14-5-000 (May 1, 2014) (delegated letter order).

terms.[63] Lastly, a series of moves and formatting changes have been made to conform the standard to the current NERC standard template. These proposed changes are shown in redline in Exhibit A.

D. Enforceability of the Proposed Reliability Standard

The proposed Reliability Standard contains Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for each of the standard's Requirements. The VRFs and VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs and VSLs are substantively unchanged from currently effective Reliability Standard TPL-001-4 and continue to comport with NERC and Commission guidelines related to their assignment.

In addition, the proposed Reliability Standard also includes Measures that support the Requirements by clearly identifying what is required and how the Requirement will be enforced. The Measures, which are unchanged from currently-enforceable Reliability Standard TPL-001-4, helps ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed implementation plan attached to this Petition as Exhibit B. Under the proposed implementation plan, Reliability Standard TPL-001-5 would become effective on the first day of the first calendar quarter that is

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[63] In 2016, the Commission approved the revised definition of Remedial Action Scheme. *See Revisions to Emergency Operations Reliability Standards; Revisions to Undervoltage Load Shedding Reliability Standards; Revisions to the Definition of "Remedial Action Scheme" and Related Reliability Standards*, Order No. 818, 153 FERC ¶ 61,228, at PP 24, 31 (2015). In 2016, the Commission approved the revised definition of Special Protection System, to have the same meaning of Remedial Action Scheme. *See N. Am. Elec. Reliability Corp.*, Docket No. RD16-5-000 (June 23, 2016) (delegated letter order).

36 months after regulatory approval. Reliability Standard TPL-001-4 would be retired immediately prior to the effective date of TPL-001-5.

Under the TPL-001-5 implementation plan, entities have additional time to come into compliance with certain Requirements related to the study of single points of failure on Protection Systems. Specifically, planning entities would have an additional 24 months after the effective date of the standard to develop Corrective Action Plans under Requirement R2, Part 2.7 for the Table 1 Category P5 planning event involving the non-redundant components of a Protection System specified in Footnote 13 items a, b, c, and d. Further, entities shall have an additional 72 months after the effective date of the standard to comply with the underlined part of Requirement R2, Part 2.7 that states: "Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments <u>but the planned System shall continue to meet the performance requirements in Table 1.</u>"

As explained in Exhibit B, the proposed implementation plan recognizes that Planning Coordinators and Transmission Planners will need time to develop a procedure or technical rationale for selecting known outages for study and for completing those planning studies. Further, the implementation plan recognizes that Planning Coordinators and Transmission Planners would need to engage in a substantial amount of work and coordination with asset owners and protection engineers to perform the new Protection System single points of failure studies and to coordinate on appropriate Corrective Action Plan measures and timetables to address System performance issues. This is especially true in cases where Corrective Action Plans may call for adding redundant Protection System components.

The proposed implementation plan recognizes the importance of ensuring that the potential risks of known outages and Protection System single points of failure are being addressed in planning studies. Based upon the considerations described above, the proposed implementation plan also provides a reasonable period of time for entities to come into compliance with the proposed standard. For these reasons, NERC respectfully requests that the Commission approve the proposed implementation plan.

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve:

- proposed Reliability Standard TPL-001-5 and associated elements included in **Exhibit A**;
- the implementation plan included in **Exhibit B**; and
- the retirement of currently effective Reliability Standard TPL-001-4.

Respectfully submitted,

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Exhibit A

Proposed Reliability Standard TPL-001-5

TPL-001-5 Clean Version

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

   - Planning Coordinator.
   - 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 MOD-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. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

1.1.5. 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 its 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. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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. Based upon this assessment, an 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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 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.

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. 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.

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.

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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5. 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 standard and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1,	The responsible entity failed to comply with two or more of the following Parts of

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	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.
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.	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.	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.	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 to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
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.	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 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 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 The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	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 The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	November 7, 2018	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

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.

TPL-001-5 Redline Version

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~4~~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

   - Planning Coordinator.
   - Transmission Planner.

5. **Effective Date:** **See Implementation Plan.**~~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~~
- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

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~~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) with a duration of at least six months.~~

~~**1.1.3.**~~**1.1.2.** New planned Facilities and changes to existing Facilities.

~~**1.1.4.**~~**1.1.3.** Real and reactive Load forecasts.

~~**1.1.5.**~~**1.1.4.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.6.**~~**1.1.5.** 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~~ its respective area, using data consistent with MOD-~~010 and MOD-012~~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.**~~**2.1.3.** 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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 ~~studied~~assessed. Based upon this assessment, an~~The~~ ~~studies~~ 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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 ~~&~~and 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<u>,</u> 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.~~

<u>**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.</u>

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~~ 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. 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.

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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5. 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~~032 standard~~s~~ and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity does not have a completed annual Planning Assessment.
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.	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.	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.	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 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.
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.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

~~B.~~D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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	Stability
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.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. 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.	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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing. e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~e.~~i. 3Ø internal breaker fault. ~~f.~~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. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions~~ or types: pilot (#85), distance (#21), differential (#87), current (#50, 51,~~, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and ~~67),~~reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

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

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

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.

~~C. Measures~~

~~**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, 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.~~

~~**M2.M1.** 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.~~

~~**M3.M1.** 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.~~

~~**M4.M1.** 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.~~

~~**M5.M1.** 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.~~

~~**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.~~

~~**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.~~

~~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.~~

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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 in Protection Systems, as identified in:
  - Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011; and
  - the report dated September 2015 by two subcommittees under NERC Planning Committee , the System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee, titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 (October 17, 2013) approving Reliability Standard TPL-001-4, relating to:
  - modeling known outages with a duration of less than six months (paragraph 40); and
  - adding stability analysis for the outage of major Transmission equipment with a lead time of one year or more (paragraph 89); and;
- To replace references to the Reliability Standards MOD-010 and MOD-012, which have been superseded by MOD-032.

General Considerations

The standard will become effective 36 months following regulatory approval. The 36-month period provides time for Planning Coordinators and Transmission Planners to develop, among other things:

- A procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- Coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional analysis required due to changes in the standard.

Following this 36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5 for Category P5 planning events involving single points of failure in Protection Systems.

Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation plan reflects consideration that Planning Coordinators and Transmission Planners will need time to conduct the new studies and analyses in order to coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5 (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2, Part 2.7 for the non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in those jurisdictions where governmental approval is required.

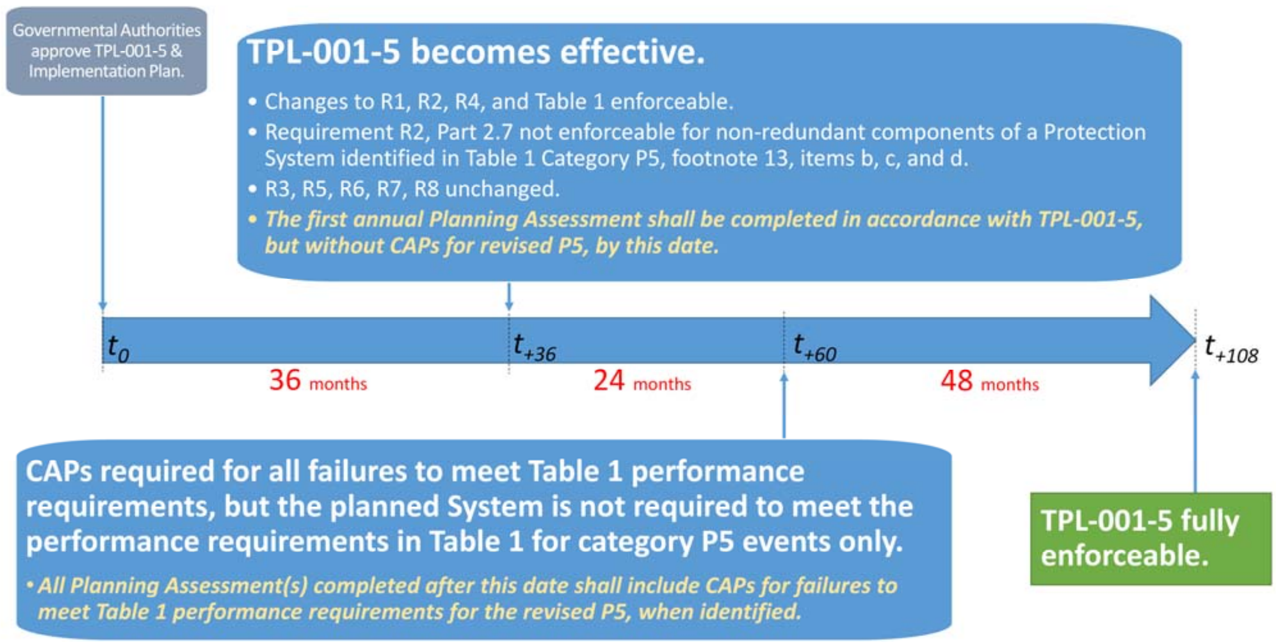

Figure 1 Implementation Plan Timeline

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 a, b, c, and d

Entities 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 a, b, c, and d until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5 with the bolded part of Requirement R2, Part 2.7 that states: "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.**"

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) 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 a, b, c, and d by 24 months after the effective date of the standard.

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.

Exhibit C

Order No. 672 Criteria

Exhibit C — Order No. 672 Criteria — Proposed Reliability Standard TPL-001-5

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The purpose of proposed Reliability Standard TPL-001-5 is to 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.

Reliability Standard TPL-001-5 requires applicable entities to perform an annual Planning Assessment of its portion of the BES covering a number of System conditions and Contingencies described in the standard. Proposed Reliability Standard TPL-001-5 enhances reliability by providing for more comprehensive consideration of Protection System single points of failure, known outages, and the unavailability of long lead-time equipment in planning studies. Specifically, proposed Reliability Standard TPL-001-5 improves upon currently effective Reliability Standard TPL-001-4 by revising the existing Table 1 planning and extreme events to require a more complete, risk-based analysis of how the failure of a non-redundant component of a Protection System would affect a planning entity's System. These revisions are based on recommendations following the analysis of data collected under request for data under

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321, 324.

Section 1600 of the NERC Rules of Procedure. The proposed standard also addresses the Commission's standard modification directives from Order No. 786 by: (i) requiring a more comprehensive analysis of known outages in planning studies; and (ii) requiring entities to consider, in Stability analysis, the impacts of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy.

2. **Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.**[3]

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard TPL-001-5 continues to apply to Planning Coordinators and Transmission Planners. The proposed standard clearly articulates the actions that each entity must take to comply.

3. **A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.**[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for proposed Reliability Standard TPL-001-5, as reflected in **Exhibit A,** are substantively unchanged from currently effective Reliability Standard TPL-001-4. The VRFs and VSLs comport with NERC and Commission guidelines related to their assignment. The VSLs are consistent with the corresponding Requirements and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences in accordance with Order No. 672.

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[3] Order No. 672 at P 322, 325.

[4] Order No. 672 at P 326.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.[5]

The proposed Reliability Standard includes Measures that support the proposed standard's Requirements by clearly identifying what is required and how the Requirements will be enforced. These Measures, which remain substantively unchanged from the Measures in currently effective Reliability Standard TPL-001-4, help provide clarity regarding how the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed standard provides for more comprehensive planning studies, thereby contributing to a more reliable BES. First, the proposed standard provides for a more complete consideration of factors for selecting which known outages will be included in Near-Term Transmission Planning Horizon studies. The revisions reflected in proposed Reliability Standard TPL-001-5 effectively address the Commission's concern that the exclusion of known outages of less than six months in TPL-001-4 could result in outages of significant facilities not being studied and account for variations in regional practices. Second, the proposed Reliability Standard provides for a more comprehensive analysis of the potential impacts of Protection System single points of failure. Third, the proposed standard requires the entity assess the impact of the possible unavailability of long lead time equipment, consistent with the entity's spare equipment strategy, in its Stability analysis. Consistent with the currently

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5 Order No. 672 at P 327.

6 Order No. 672 at P 328.

effective standard, entities retain flexibility to select appropriate mitigation measures in the event System performance issues are identified. The proposed standard thereby achieves its reliability goal effectively and efficiently.

6. **Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the revisions reflected in proposed Reliability Standard TPL-001-5 provide significant benefits for the reliability of the Bulk Power System by providing for more comprehensive planning studies: The proposed Reliability Standard does not sacrifice excellence in operating system reliability for costs associated with implementation of the Reliability Standard.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**[9]

The proposed Reliability Standard has no undue negative effect on competition. The proposed Reliability Standard requires the same performance by each of applicable entity. The

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[7] Order No. 672 at PP 329, 330.

[8] Order No. 672 at P 331.

[9] Order No. 672 at P 332.

proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective date for the proposed Reliability Standard is just and reasonable and appropriately balances the urgency in the need to implement the proposed Reliability Standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for TPL-001-5 that is the first day of the first calendar quarter that is 36 months after regulatory approval. Reliability Standard TPL-001-4 would be retired immediately prior to the effective date of TPL-001-5.

Under the TPL-001-5 implementation plan, entities have additional time to come into compliance with certain Requirements related to the study of single points of failure on Protection Systems. Specifically, planning entities would have an additional 24 months after the effective date of the standard to develop Corrective Action Plans under Requirement R2, Part 2.7 for the Table 1 Category P5 planning event involving the non-redundant components of a Protection System specified in Footnote 13 items a, b, c, and d. Further, entities shall have an additional 72 months after the effective date of the standard to comply with the underlined part of Requirement R2, Part 2.7 that states: "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."

The proposed effective date and phased compliance dates are reflected in the proposed implementation plan, attached as **Exhibit B**.

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[10] Order No. 672 at P 333.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. **Exhibit G** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[12]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[13]

No other factors relevant to whether the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential were identified.

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[11] Order No. 672 at P 334.

[12] Order No. 672 at P 335.

[13] Order No. 672 at P 323.

Exhibit D

Analysis of Violation Risk Factors

and

Violation Severity Levels

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 instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

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:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

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.

Exhibit E

Mapping Document

Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **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. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **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-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]*	Requirement R1 body has been updated to reference MOD-032 standard number in body of requirement. Requirement R1, Part 1.1.2 and subparts have been deleted. Selection of known outages will be addressed in Requirement R2, Parts 2.1.4 and 2.4.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. **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	**1.1.** System models shall represent: **1.1.1.** Existing Facilities. **1.1.2.** New planned Facilities and changes to existing Facilities. **1.1.3.** Real and reactive Load forecasts. **1.1.4.** Known commitments for Firm Transmission Service and Interchange. **1.1.5.** Resources (supply or demand side) required for Load.	
TPL-001-4, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.2, 2.7.3, 2.7.4	TPL-001-5, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.2, 2.7.3, 2.7.4	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Parts 2.8, 2.8.1, 2.8.2	Parts 2.8, 2.8.1, 2.8.2	
TPL-001-4, Requirement R2 R2 Part 2.1.4 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.	TPL-001-5, Requirement R2 R2 Part 2.1.3 2.1.3 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.	Requirement R2, Part 2.1.4 moved to Requirement R2, Part 2.1.3

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	• Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of known Transmission outages.	
TPL-001-4, Requirement R2 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.	TPL-001-5, Requirement R2 2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with	<u>Requirement R2 Part 2.1.3 moved to Requirement R2 Part 2.1.4</u> A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1	impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4.
TPL-001-4, Requirement R2 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 studied. The studies 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.	TPL-001-5, Requirement R2 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. Based upon this assessment, an analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to	<u>Requirement R2, Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5</u>

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	experience during the possible unavailability of the long lead time equipment.	
TPL-001-4, Requirement R2 2.4.3. 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.	TPL-001-5, Requirement R2 2.4.3. 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.	Requirement R2, Part 2.4.3 has been moved back to 2.4.3 as it was in TPL-001-4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	TPL-001-5, Requirement R2 2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as	<u>TPL-001-5, Requirement R2, Part 2.4.4</u> <u>TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4</u> Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	those following P3 or P6 category events in Table 1.	
	TPL-001-5, Requirement R2 **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.	<u>TPL-001-5, Requirement R2, Part 2.4.5</u> Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.
TPL-001-4, Requirement R2 Requirement R2 Part 2.7	TPL-001-5, Requirement R2 Requirement R2 Part 2.7 **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the	<u>TPL-001-5, Requirement R2,</u> <u>Requirement R2, Part 2.7</u>

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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:	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 2.1.3 and 2.4.3. The Corrective Action Plan(s) shall:	Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard.
TPL-001-4, Requirement R2, Part 2.7 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	TPL-001-5, Requirement R2, Part 2.7 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	<u>Requirement R2, Part 2.7</u> <u>Updated to reflect NERC Glossary Term</u>

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Special Protection Systems. • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability	removal of Transmission and generation Facilities and any associated equipment. • Installation, modification, or removal of Protection Systems or Remedial Action Schemes. • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	• 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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Use of rate applications, DSM, new technologies, or other initiatives.	technologies, or other initiatives.	
TPL-001-4, Requirement R3 **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	TPL-001-5, Requirement R3 **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	<u>Requirement R3, Part 3.2</u> Document internal conforming clean-up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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:	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. 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. **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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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-	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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. 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.	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.	
TPL-001-4, Requirement R4	TPL-001-5, Requirement R4	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Parts 4.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	Parts 4.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	
TPL-001-4, Requirement R4 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 is not considered pulling out of synchronism.	TPL-001-5, Requirement R4 TPL-001-4, Requirement R4 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.	<u>Requirement R4, Part 4.1.1</u> <u>Updated to reflect NERC Glossary Term</u>
TPL-001-4, Requirement R4 **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.	TPL-001-5, Requirement R4, **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	<u>TPL-001-5, Requirement R4, Part 4.2</u> Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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:	expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2. Requirement 4, Part 4.1.1

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. **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:	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

Exhibit F

Technical Rationale

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10

Technical Rationale for TPL-001-05

October 2018

RELIABILITY | ACCOUNTABILITY




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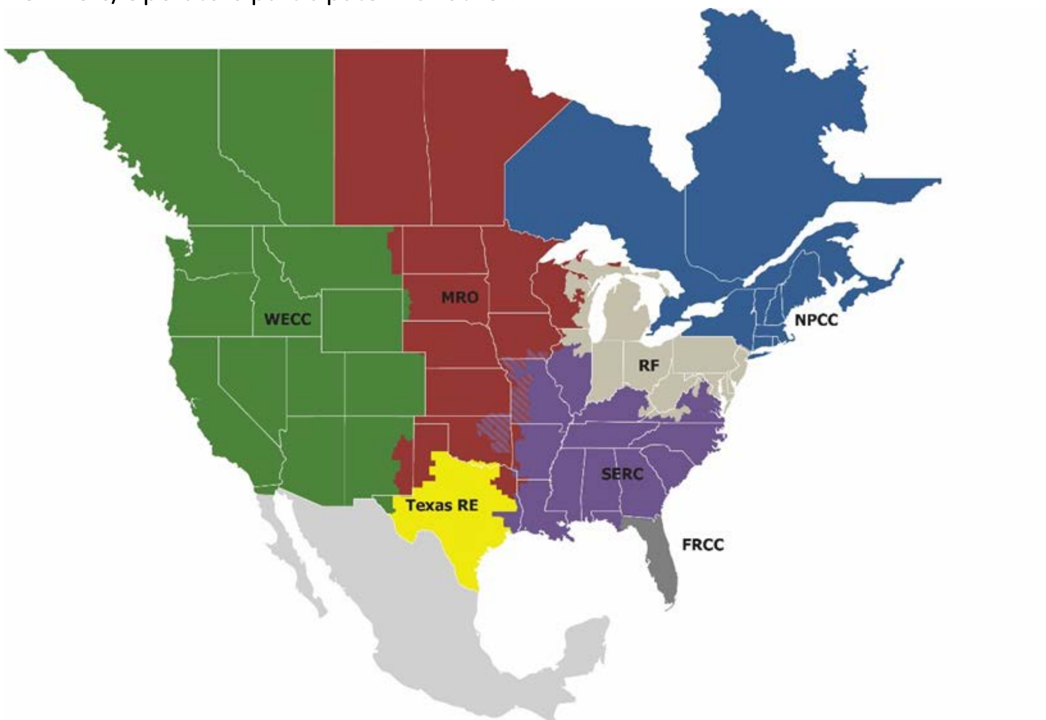
Table of Contents

Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standard Drafting Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," the Category P5 event incorporates Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 Planning Events and Stability Extreme Events.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, that Category P3 and P6 do not sufficiently cover planned maintenance outages, and the Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration, shift the consideration of known outages from Requirement R1, which requires what System models shall represent, to Requirement R2, Parts 2.1 and 2.4, which require the study and assessment of known outages. Further, proposed revisions include a requirement to document an outage coordination procedure or the technical rationale for the determination of which known outages to study. Proposed revisions also included the addition of stability assessment for long lead equipment that does not have a spare.

Summary of proposed revisions

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Removed this requirement.
- Requirement R2, Part 2.1.4 – Added model conditions for steady state analysis of P0 and P1 events for known outages.
- Requirement R2, Part 2.4.4 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R3, Part 3.2 – Document internal conforming clean-up to incorporate the last sentence of Part 3.5.

- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify the SPF that should be considered.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with SPF in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order No. 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF.

The SDT strongly considered the recommendations of the SPCS and SAMS report, recognizing that the purpose of that report was to determine whether a reliability concern existed demanding NERC to address the study of SPF on Protection Systems. The formation of the Project 2015-10 directly resulted from the SPCS and SAMS report recommendations. However, the SDT's obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments which adequately account for the reliability risk posed by SPF on Protection Systems.

FERC Order No. 786

In FERC Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order No. 786. The white paper provides extensive general discussion regarding the directives.

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[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System (BES) were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In FERC Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the technical conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC technical conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC Planning Committee (PC) and Operating Committee (OC), summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action.

[3] *See [Industry Advisory: Single Point of Failure](http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf)*
http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf

To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order No. 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SDT strongly considered the recommendations of the SPCS and SAMS report, as specified by the Project 2015-10 Single Points of Failure Standards Authorization Request (SAR). The SDT recognized that its obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments. The SPCS and SAMS report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 SDT are summarized in the following section.

Revisions to TPL-001-4

Single Points of Failure – Category P5 Planning Events

The SPCS and SAMS report states, “Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists)”.

The modifications to the Category P5 Planning event description are intended to be aligned with the changes to the Table 1, Footnote 13. The SDT has modified Table 1, Footnote 13 to capture the SPCS/SAMS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified SPF of concern. Footnote 13 describes the non-redundant Protection System components to be considered for Category P5 Planning Events, and is discussed further below.

The Table 1 Category P5 event describes a Contingency where a single line-to-ground (SLG) fault occurs and Delayed Fault Clearing results due to the failure of the Protection System, protecting the Faulted element, to operate as designed. Typically, the two most important aspects of the P5 event that affect simulation are the magnitude of SLG fault current and the mode of Protection System failure leading to Delayed Fault Clearing. The latter is especially important and the mode of Protection System failure details make the P5 event unique. The Transmission Planner or Planning Coordinator must be cognizant of the time period during which the Protection System removes Elements from service, as well as the sequence of their removal during isolation of the fault. By definition, Normal Clearing is not expected when a non-redundant component of a Protection System is simulated to have failed; the P5 event implies that the Protection System does not operate as designed to clear the SLG fault in the time normally expected with proper functioning of the installed Protection System. Therefore, when a non-redundant component of a Protection System fails, Delayed Fault Clearing results. This means that correct operation of the backup Protection System occurs with the intentionally designed time delay before fault clearing. Additionally, there may be significant differences in final System configuration due to the Protection System operation to clear the faulted Element. For example, more System Elements may be removed from service when the backup Protection System operates, consistent with Delayed Fault Clearing, than may be expected during primary Protection System operation expected for Normal Clearing. The expected time delays for Protection System operation are critical for proper simulation of the P5 event.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 Planning Events will likely be to add Protection System component redundancy, consistent with the components to be considered in Footnote 13. Protection System redundancy changes to address Category P5

Event concerns should also reduce or even negate non-redundant components that need to be considered in assessing System performance resulting from simulation of the 2e-2h Extreme Events; hence, potentially mitigating many concerns.

Clarification: Why address SPF in TPL-001 and not create a new Reliability Standard for this purpose?

As part of the recommendations from the SPCS and SAMS report, the option to create a new Reliability Standard to address SPF in the Protection System was considered. Both a new TPL standard for planning-related studies and assessment, as well as a new Protection and Control standard to specify Protection System redundancy were debated by SPCS and SAMS. Ultimately, the recommendation of the SPCS and SAMS report, leading to the formation of the Project 2015-10 SDT, focused upon the simulation and study assessment of the Transmission system given non-redundant components of the Protection System instead of mandating a level of redundancy across a diverse set of equipment and utilities in North America.

It is important to emphasize that modifications to the TPL-001-5 Table 1 Category P5 Planning Event, the TPL-001-5 Table 1 Extreme Stability Events, and related changes to Table 1, Footnote 13 do not establish or mandate a level of redundancy for Protection Systems. Quite the contrary: the modifications presented in TPL-001-5 require planning entities to consider the non-redundant components of Protection Systems that may exist within their respective Systems, to execute appropriate studies, and to assess the impacts that these SPF may have upon the ability to meet Table 1 System performance requirements given Delayed Fault Clearing. TPL-001-5 does not mandate redundancy; TPL-001-5 requires that some non-redundancy components of a Protection System be considered during annual Planning Assessments.

Clarification: Why is consideration of fault duration significant for the P5 Planning Event?

A Protection System is designed to isolate faulted equipment within an expected time duration following fault initiation. When the Protection System does not operate as designed or fails to isolate faulted equipment within the time normally expected with its proper functioning, backup protection capabilities must act to clear the fault. The SDT recognized that Protection Systems used for backup protection are designed with intentional time delays that inherently allows primary protection to actuate first. This is consistent with the Table 1 Planning Event P5 which is characterized by its prescribed Delayed Fault Clearing. The SDT recognized that the sequencing, causality, and mode of failure of a non-redundant component of a Protection System leads to Delayed Fault Clearing by the operation of backup protection, whether local (e.g., breaker failure initiation) or remote (e.g., remote-end terminal tripping consistent with zonal backup protection). The SDT believed the existing defined terms Normal Clearing and Delayed Fault Clearing were appropriate for the revised Table 1 Planning Event P5, as well as the revised Table 1 Footnote 13.

Clarification: What is the difference between a top-down versus bottom-up approach to Category P5 Events?

As part of simulating and analyzing results of P5 Event assessments, two common approaches to the Stability portion of simulations may be appropriate for planning entities to undertake. The first, referred to as the top-down approach, may initially focus upon determining critical clearing times for an entity's System topology given SLG faults. Once critical clearing times are obtained, the planning entity has the opportunity to collaborate with System Protection personnel to assess whether the installed Protection System may achieve the required performance. An advantage of the top-down approach is that the analytical burden to determine critical clearing times is front-loaded upon the planning entity and specific details regarding the Protection System are unnecessary prior to executing dynamics simulations. Conversely, the bottom-up approach may commence by the planning entity requesting the detailed causality and clearing times for SPF on the Protection System from Protection System personnel, requiring an extensive review of installed Protection Systems at the outset. While this approach may delay the execution of P5 Event studies, it may eliminate System topology that is not susceptible to SPF on the Protection System based upon Protection System personnel input and reduces the planning entity's dynamics simulation burden. Whether utilizing a top-down, bottom-up, combination of the two, or any other appropriate approach, the obligation specified in Table 1, Footnote 13 is for the planning entity to consider the non-redundant components of a Protection System that may lead to Delayed Fault Clearing when simulating the P5 Event.

Clarification: Is backup protection redundant?

The majority of BES Protection Systems are designed with overlapping zonal protection, including backup systems which eventually clear a fault in the event of a failure of the Protection System which is designed for Normal Clearing. Backup Protection Systems are not redundant for purposes of TPL-001-5 Table 1, Category P5 Events because they result in Delayed Fault Clearing and/or trip more Elements than the primary Protection System designed for Normal Clearing. Where the Protection System is designed with backup protections, the backup protection clearing time for a SLG fault must be the same as the clearing time for the primary Protection System designed for Normal Clearing, and must trip identical Elements, in order for the backup Protection System to be considered redundant to the primary Protection System. The SDT expects this type of design to be rare in its implementation, and correspondingly, backup protection is not considered redundant.

Table 1, Footnote 13

Footnote 13 is included in the TPL-001-5 Reliability Standard for the purpose of focusing the Transmission Planner and Planning Coordinator consideration of non-redundant components of a Protection System that may, when they fail, lead to Delayed Fault Clearing of the SLG fault simulated as part of the P5 event.

The SPCS and SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A factor that the SDT considered when seeking to translate the SPCS and SAMS recommendations into the proposed TPL-001-5 Table 1, Footnote 13 was the need for Planning Coordinators and Transmission Planners to collaborate with System Protection personnel. The SDT recognized that the planning entities do not always have enough information alone to consider Protection System modes of failure or Delayed Fault Clearing than may result. Likewise, the SPCS and SAMS recommendations were adapted to target the potential non-redundant components of a Protection System that may likely need System Protection personnel input when determining how study simulations, performed by the planning entity, should be executed. Based on discussion and industry comment, the SDT revised Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;

- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS and SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13. Similarly, control circuitry whose failure does not prevent Normal Clearing of a fault, such as reclosing circuitry and reclosing relays, is omitted from Footnote 13 consideration.

Clarification: Does Footnote 13 prescribe redundancy?

It is emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

Clarification: Why is monitored and reported to a Control Center used in parts of Footnote 13?

The SDT recognized that some components of a Protection System may be monitored and their integrity reported to a Control Center. Different than an indication of a component failure that may be displayed in a remote site or in a location that may go unnoticed for a period, reporting to a Control Center implies that an unsatisfactory condition would be identified and corrective action be directed in short order. It is noted that short order is consistent with the “within 24 hours of detecting an abnormal condition” recommendation of the SPCS/SAMS report. Given that a risk-based approach to non-redundant components of a Protection System is appropriate, the SDT believed that components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.

Clarification: Why are relays that respond to electrical quantities addressed?

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the SDT sought to limit the scope of Footnote 13a with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. A SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the SDT did not include backup protective relays in the scope of Footnote 13a given that a SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The SDT recognized that BES Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be a SPF, an internal transformer tank fault may not lead to Delayed Fault Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event (See Figure 1 and 2).

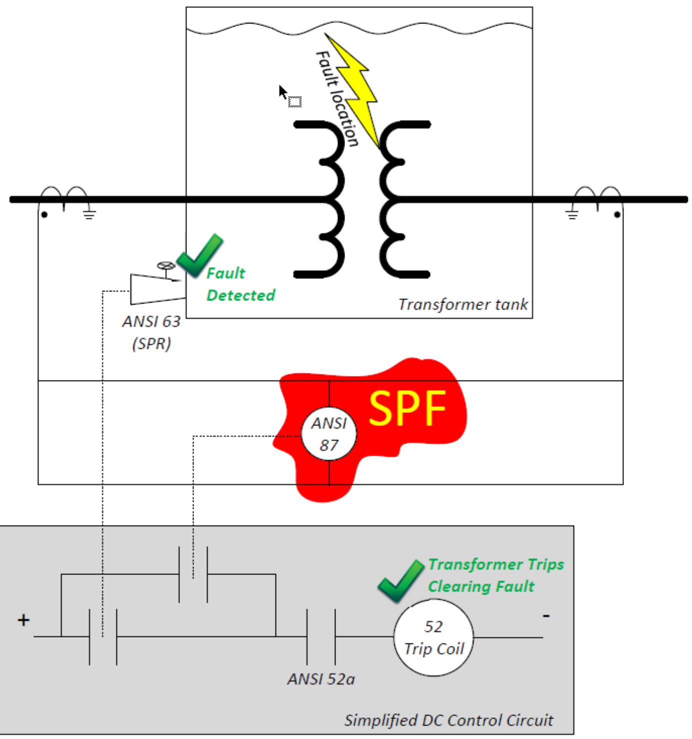

Figure 1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

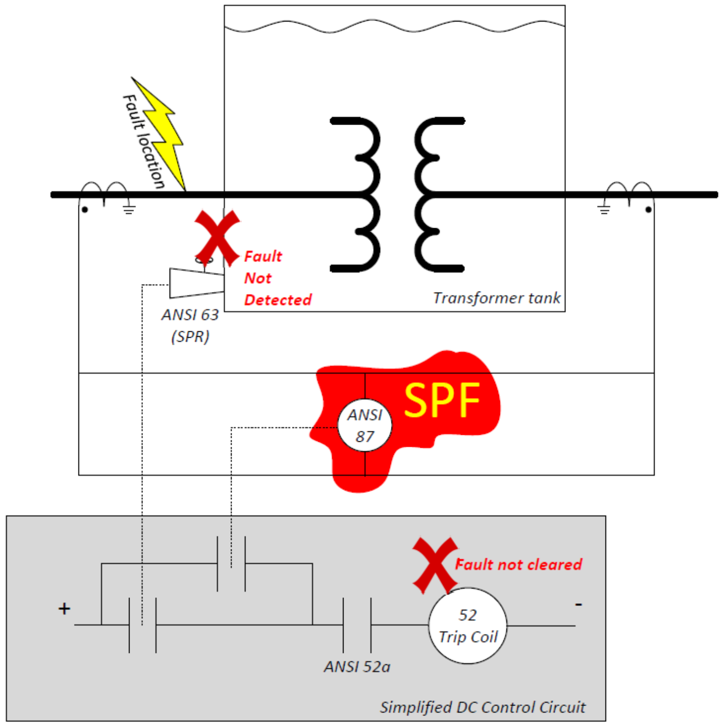

Figure 2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Clarification: What is comparable and what is not comparable for purposes of footnote 13?

The use of "comparable" in Table 1, Footnote 13a applies only to alternatives for a single protective relay that responds to electrical quantities. For an alternative to be comparable to a single protective relay that responds to electrical quantities, the alternative must operate as designed to clear the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly. Clearly, any alternative to a single protective relay that responds to electrical quantities may result in a different Element tripping sequence, leading to a different System topology after fault clearing which must be considered. Therefore, a comparable alternative to a single protective relay that responds to electrical quantities must result in fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements.

Clarification: Are separate Normal Clearing times comparable?

The SDT cannot anticipate all Protection System designs. However, the SDT's intent for alternatives to a single protective relay that responds to electrical quantities is implicit in the principle of comparable Normal Clearing times. In some cases, multiple layers of protection may overlap towards achieving a common System protective objective: to provide Normal Clearing. Examination of this design towards the common objective may indicate the Normal Clearing times are comparable. An example of this type of design may be a piloted relay for high-speed fault clearing used in conjunction with a non-piloted relay for primary or fast fault clearing. While these two relays may have different Normal Clearing times, their protective objective is common: to provide Normal Clearing. The clearing times of these two relays may be different, but are likely comparable. The applicable entity must understand the design of their own Protection System for the purpose of considering non-redundant components. Moreover, determination of whether alternatives, which may or may not respond to electrical quantities, provide comparable Normal Clearing times must be made with regard to the Protection System design, the expected fault clearing time, and the protective objective of its proper functioning.

Clarification: Why are communication-aided Protection Systems addressed?

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The SDT augmented the SPCS/SAMS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The SDT concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the BES can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Clarification: Why are DC supplies addressed?

The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding station Protection System DC supply. Failure of a single station Protection System DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The SDT partly modified the SPCS/SAMS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit. Therefore, this requirement may be more applicable to legacy systems.

Clarification: What differentiates a single station DC supply (Footnote 13c) from a single control circuitry (Footnote 13d)?

The station DC supply includes station battery, battery chargers and non-battery-based dc supply, as enumerated in the NERC Glossary of Terms definition of Protection System. The control circuitry includes everything from where the station DC supply terminates through and including the trip coils, including the wiring, as well as auxiliary and lockout relays. Further, the NERC Technical Paper *"Protection System Reliability Redundancy of Protection System Elements"* (November 2008) shows a demarcation between DC supply and the remainder of DC control circuitry. The SAMS and SPCS report and recommendations align with Figure 5-12 from this technical paper, shown below as Figure 3.

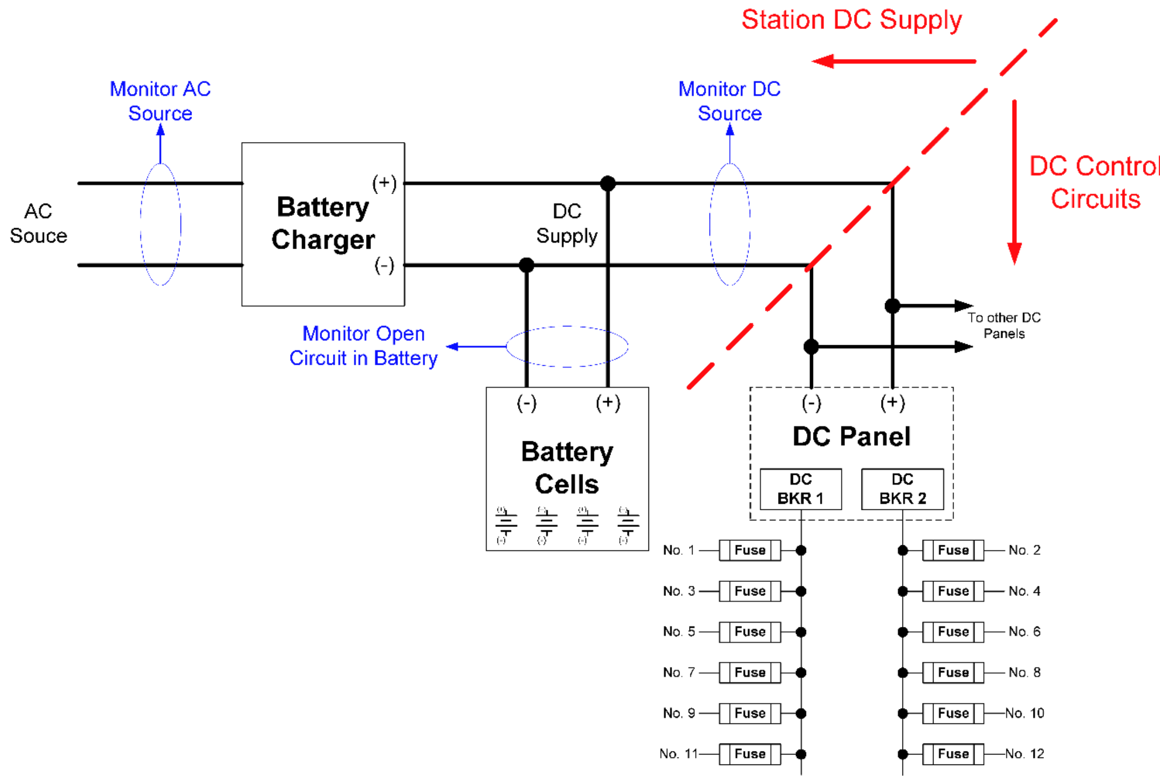

Figure 3 – Station DC supply and monitoring (Figure 5-2, from NERC Technical Paper "Protection System Reliability Redundancy of Protection System Elements", Nov 2008)

Simply monitoring for low voltage on the DC supply may omit situations where the DC supply voltage is satisfactory but the source path to DC control circuits may be open circuited. Thus, monitoring for low voltage and open circuit of the DC supply should be considered. Additionally, while the wiring in both the DC supply and the DC circuit have lower probabilities of failure as compared to other Protection System components, the SPCS and SAMS report identified this as a SPF risk.

Clarification: Is a battery charging system appropriate redundancy for the battery?
Battery chargers may not be of sufficient power to source current necessary to operate one or more breakers. For example, it is unlikely that a battery charger without a station battery in parallel would be capable of opening several breakers when demanded by a bus differential Protection System operation. Therefore, a battery charger cannot take the place of a redundant battery DC supply.

Clarification: Why is control circuitry addressed?
The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding Protection System DC control circuitry. Failure of a Protection System single control circuitry is a significant point of failure as it will prevent proper tripping and, depending upon its design and mode of failure, may also prevent the initiation of breaker failure protection. Breaker failure is addressed by the Table 1 Planning Event P4 and is discussed in the next section. Further, most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions, such as multiplexing trip signals for differential or breaker failure initiation. Single control circuitry should be considered a non-redundant component of a Protection System given that Delayed Fault Clearing, including significantly delayed remote end or backup clearing, is expected when the non-redundant auxiliary or lockout relay device within the single control circuitry fails.

The single control circuitry is demarcated from the DC supply through and including the trip coil(s) for the purpose of including all devices in the control circuitry which, if failed, may prevent proper Protection System action leading to Delayed Fault Clearing. Trip coils are commonly employed in pairs (dual) for the purpose of incorporating redundancy to actuate the tripping of a circuit breaker or other interrupting device. However, the SDT partly modified the SPCS/SAMS recommendation regarding single control circuitry recognizing that some Protection System designs include a single trip instead of dual trip coils. When a single trip coil is employed, monitoring and reporting the status of the single trip coil can be considered as a sufficient alternative to its physical redundancy given that prompt notification and remediation is expected which minimizes the risk the trip coil failure. However, the trip coil(s), whether implemented singly or in pairs, are only part of the single control circuit; all its constituent parts should be included when considering whether the single control circuit may be a non-redundant component of a Protection System.

The Distinction between Category P4 and Category P5 Planning Events

"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 Planning Events. The sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Fault Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed Fault Clearing associated with circuit breaker failure. Likewise, the Delayed Fault Clearing time that results from a Category P5 Event may be significantly longer that that expected when simulating Category P4 Event.

It is noted that there may be many instances where a fault followed by a breaker failure results in the exact same study simulations as a fault followed by a failure of a non-redundant component of a Protection System. There could be slight differences in clearing times and the Planning Coordinator or Transmission Planner may choose to simulate a P4 and P5 as one study using the longest expected clearing time. However**,** in the event of a bus fault followed by a bus differential protection failure, there may be a single relay (ANSI device 86) communicating to several breakers attached to the faulted bus. A bus fault on a breaker and a half configuration or double breaker double bus configuration may be particularly problematic in this case. For the Category P5 Event simulating this type of Protection System failure, none of the breakers which should open to clear the fault will receive the appropriate signal from the failed SPF relay and will not clear the bus fault. This makes the bus differential P5 Event significantly more severe than the P4 Event. The FERC Order 754 Section 1600 Data Request was specific to bus faults followed by a SPF of the Protection System.

In some cases, a P4 Event simulation at a specific location will be the same as the P5 Event simulation. For example: the failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open to clear a fault. Therefore, the P4 Event and the P5 Event may simulate the identical causality. However, if this simulation results in a performance requirement violation, the CAP must include mitigations for the P4 Event as well the P5 Event.

Extreme Events 2e-2h listed from the stability column of Table 1

Analysis of the data collected under the FERC Order No. 754 Section 1600 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further consideration. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis should be placed on assessment of three-phase faults involving a SPF on the Protection System. This concern, made manifest through the study of a three-phase fault and a SPF on a Protection System, is appropriately addressed as an extreme event in TPL-001-5, Requirement R4, Part 4.2. While less probable than SLG faults, three-phase faults frequently initiate as single-phase-to-ground with Delayed Fault Clearing and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1, Category P5 Event. TPL-001-5, Requirement R4, Part 4.2, specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of extreme events. Thus, the SDT has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but encourages consideration of implementing mitigating actions if it is cost-effective to do so.

Requirement R3, Parts 3.2 and 3.5 and Requirement R4, Parts 4.2 and 4.5

The SDT proposes non-substantive editorial changes to combine part of Requirement R3, Part 3.5 with Requirement R3, Part 3.2. The rearrangement of Requirement 3, Parts 3.2 and 3.5 were done to improve consistency within the Standard and do not create any new requirements. This is also true for Requirement R4, Part 4.2 and 4.5. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable, cost-effective measures to lessen the risk or severity of these events.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

FERC Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not “hypothetical outages” and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing “with duration of at least six months” and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order No. 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an “academic exercise” due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order No. 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

Revisions to TPL-001-4

Requirement R2, Parts 2.1.4 and 2.4.4

The SDT gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying, and sometimes conflicting, perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the Transmission Planner or Planning Coordinator.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective continent wide means of addressing the FERC directive. However, FERC Order No. 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available. The proposed modification is for consideration of known outages beyond, and therefore outside of, the Operations Planning time horizon.

The most prominent change the SDT proposes to address the FERC directive was to migrate the assessment of known outages from Requirement R1, which requires that System models shall represent, to Requirement R2, Parts 2.1 and 2.4 which requires how analyses shall be assessed and supported by studies. The SDT believed that this proposed change to where the assessment of known outages is specified in the TPL-001-5 requirements better aligns the approach necessary for the planning entities to execute their annual Planning Assessments.

The SDT modified Requirement R2, Part 2.1.4 and 2.4.4 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that Planning Coordinators and Transmission Planners currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be considered. The Planning Coordinator and Transmission Planner must have either a documented outage coordination procedure or technical rationale to select which known outages shall be assessed. The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination. Consistent with the intention of Order No. 786, the SDT included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be assessed. It is only necessary to consider known outages expected to cause more severe System impacts, such as those that may result in Non-Consequential Load Loss for P1 event in Table 1. This allows the Planning Coordinator and Transmission Planner to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary assessment of outages which the Planning Coordinator and Transmission Planner do not expect to be problematic. The System conditions, such as peak or Off-Peak, that are expected during the period when the known outage is planned further limits the "non-hypothetical" analyses that may be performed. While it is inappropriate to assume that all known outages simulated in conjunction with Category P0 or P1 Events are identical to Category P3 or P6 Events, past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1 . However, it is imperative for the Planning Coordinator or Transmission Planner to document the justification for

supporting the known outage exclusion based upon past or current studies and why the post-Contingency System conditions and configuration are comparable in their technical rationale.

Clarification: Does TPL-001-5 duplicate requirements of IRO-017-1 for outage coordination?

The SDT was concerned that in order for the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, it must first assess the known outages as part of that Planning Assessment. However, if the Planning Coordinator or Transmission Planner does not know what outages to study, clearly outages may be omitted from having the opportunity for jointly developed solutions with the Reliability Coordinator, required in IRO-017-1. The SDT believed that the feedback loop between the planning entities and the Reliability Coordinator ends with the planning entities presenting their study results in the Planning Assessment, but must begin with strong collaboration and sourcing of information regarding known outages that should be studied beyond the Operations Horizon by the Reliability Coordinator. Therefore, the SDT does not believe that there is duplication between the proposed TPL-001-5 and IRO-017-1 standards. Moreover, the SDT believes there is an implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon.

FERC Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

Clarification: Does TPL-001-5 prescribe an entity's spare equipment strategy?

No. The SDT addressed the guidance in paragraph 89 of Order No. 786 regarding stability analysis to assess System performance for conditions expected during possible unavailability of long lead time equipment in TPL-001-5 Requirement R2, Part R2.4.5. The SDT recognized that "spare equipment strategy" is not a NERC-defined term and believed it was sufficient to allow flexibility for applicable entities to conduct both steady state and stability analysis required by TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5. For example, an entity's spare equipment strategy may include the warehousing of a replacement transformer to be installed given the failure of an in-service BES transformer. When an entity's spare equipment strategy may prevent major Transmission equipment from being out-of-service for one year or more, this possible equipment unavailability need not be assessed as part of TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have “a lead time of one year or more.”
- Each long-lead time Element that is removed from service creates a new operating condition considered the “normal” (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2, Part 2.4.5

Consistent with FERC’s Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 SDT revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity’s spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning entities and System Protection personnel that will need to collaborate when conducting the studies and submitting the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines. Coordination with Generator Owners, Transmission Owners, and Distribution Providers will be necessary to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant component of a Protection System could result in a potential reliability risk. Transmission Planners and Planning Coordinators must obtain this information, as well as resulting fault clearing times, to perform proper studies.

Exhibit G

Summary of Development

and

Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard TPL-001-5 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process Manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team ("SDT") members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

Project 2015-10 – Single Points of Failure TPL-001 was initiated in 2015 following the submission of a Standards Authorization Request ("SAR") to address findings and recommendations from a report prepared by the NERC System Protection and Control Subcommittee and System Modeling and Analysis Subcommittee on Protection System single points of failure. The SAR was initially posted for a 30-day informal comment period from November 12, 2015 through December 17, 2015. The SAR was subsequently expanded to address the outstanding FERC directives from Order No. 786 and to update the MOD references in the TPL standard. The revised SAR was posted for an additional 30-day informal comment

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2012).
2 The NERC *Standard Processes Manual* is available at http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

period from May 26, 2016, through June 24, 2016. The SAR was accepted by the SC on July 20, 2016.

B. First Posting – Informal Comment Period

Proposed Reliability Standard TPL-001-5 was posted for a 30-day informal comment period from April 25, 2017 through May 24, 2017. There were 63 sets of responses, including comments from approximately 180 different individuals and approximately 129 companies representing all 10 industry segments.[3]

C. Second Draft – Comment Period, Initial Ballot, and Non-binding Poll

Proposed Reliability Standard TPL-001-5 and the associated Violation Risk Factors ("VRFs"), and Violation Severity Levels ("VSLs") were posted for a 45-day formal comment period from September 8, 2017 through October 23, 2017, with parallel initial ballot and non-binding poll held during the last 10 days of the comment period from October 13, 2017 through October 23, 2017. The initial ballot received a 30.5% industry approval with a quorum of 82.99%. The related non-binding poll received a 31.03% industry approval with a quorum of 79.56%. There were 70 sets of responses, including comments from approximately 192 different individuals and approximately 118 companies, representing all 10 industry segments.[4]

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[3] NERC, *Consideration of Comments*, Project 2015-10 – Single Points of Failure | TPL-001-5, (July 27, 2017), *available at* https://www.nerc.com/pa/Stand/Project_201510%20Single%20Points%20of%20Failure_TPL001_DL/Project_2015-10_Consideration_of_Comments_07272017.pdf.

[4] NERC, *Comments Received*, Project 2015-10 – Single Points of Failure | TPL-001-5, (October 25, 2017), *available at* https://www.nerc.com/pa/Stand/Project_201510%20Single%20Points%20of%20Failure_TPL001_DL/2015-10_TPL-001-5_Comments_Received_10252017.pdf.

D. Third Draft – Comment Period, Additional Ballot, Non-binding Poll and Implementation Plan Initial Ballot

Proposed Reliability Standard TPL-001-5 was posted for a second 45-day formal comment period and additional ballot from February 23, 2018 through April 23, 2018.[5] A parallel initial ballot for the Implementation Plan and a non-binding poll of the associated VRFs and VSLs held during the last 10 days of the comment period from April 13, 2018 through April 23, 2018. The additional ballot for TPL-001-5 received a 26.44% industry approval with a quorum of 80.27%. The related non-binding poll for the associated VRFs and VSLs received a 27.01% industry approval with a quorum of 76.28%. The initial ballot for the Implementation Plan received a 41.13% industry approval with a quorum of 78.23%. There were 70 sets of responses, including comments from approximately 190 different individuals and approximately 117 companies, representing all 10 industry segments.[6]

E. Fourth Draft – Comment Period, Additional Ballot and Non-binding Poll

Proposed Reliability Standard TPL-001-5 was posted for a third 45-day formal comment period and additional ballot from July 30, 2018 through September 14, 2018,. A parallel additional ballot for the Implementation Plan and a non-binding poll of the associated VRFs and VSLs were held during the last 10 days of the comment period from September 5, 2018 through September 14, 2018. The additional ballot for TPL-001-5 received a 69.07% industry approval with a quorum of 75.85%. The additional ballot for the proposed Implementation Plan received a 73.27% industry approval with a quorum of 75.51%. The related non-binding poll for the associated VRFs and VSLs received a 68.64% industry approval with a quorum of 78.47%.

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5 The comment period for this posting, which was initially scheduled to close on April 9, 2018, was extended to April 23, 2018 following the posting of updated documents on March 8, 2018. The ballot dates were adjusted accordingly.

6 NERC, *Consideration of Comments*, Project 2015-10 – Single Points of Failure | TPL-001-5, (July 2018), *available at* https://www.nerc.com/pa/Stand/Project_201510%20Single%20Points%20of%20Failure_TPL001_DL/2015-10_TPL-001-5_Consideration_of_Comments_07302018.pdf.

There were 51 sets of responses, including comments from approximately 148 different individuals and approximately 96 companies, representing all 10 industry segments.[7]

F. Final Ballot

Proposed Reliability Standard TPL-001-5 and the Implementation Plan were posted for a 10-day final ballot period from October 11, 2018 through October 22, 2018. The proposed standard received a 66.69% industry approval with a quorum of 86.39%. The proposed Implementation Plan received a 72.44% industry approval with a quorum of 86.73%.

G. Board of Trustees Approval

Proposed Reliability Standard TPL-001-5, the Implementation Plan, and the associated VRFs and VSLs were adopted by the NERC Board of Trustees on November 7, 2018.[8]

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7 NERC, *Consideration of Comments*, Project 2015-10 – Single Points of Failure | TPL-001-5, (October 2018), *available at* https://www.nerc.com/pa/Stand/Project_201510%20Single%20Points%20of%20Failure_TPL001_DL/2015-10_TPL-001-5_Draft_4_Consideration_of_Comments_10112018.pdf.

8 NERC, *Board of Trustees Agenda Package*, Agenda Item 7c (TPL-001-5 — Transmission Planning Performance Requirements), *available at* https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Of_Trustees_November_7_2018_Meeting_Agenda_Package.pdf.

Complete Record of Development History

Project 2015-10 Single Points of Failure TPL-001

Related Files

Status
The final ballots for **TPL-001-5 – Transmission System Planning Performance Requirements** and the **implementation plan,** concluded **8 p.m. Eastern, Monday, October 22, 2018**. The voting results can be accessed via the links below. The standard and implementation plan will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background
The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Standard(s) Affected: TPL-001-4 - Transmission System Planning Performance Requirements

Purpose/Industry Need
The proposed standard project will benefit reliability by providing clear, unambiguous and results-based reliability standard requirements to address the assessment's recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request."

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **TPL-001-5** Clean **(77)**| Redline to Last Approved **(78)**| Redline to Last Posted **(79)** Implementation Plan Clean **(80)**| Redline **(81)**	Final Ballots Info **(85)** Vote	10/11/18 - 10/22/18	Ballot Results TPL-001-5 **(86)** Implementation Plan **(87)**	

Supporting Materials VRF/VSL Justification **(82)** Mapping Document **(83)** Technical Rationale **(84)**				
Draft 4 **TPL-001-5** Clean **(59)**| Redline to Last Approved **(60)**| Redline to Last Posted **(61)** Implementation Plan Clean **(62)**| Redline to Last Posted **(63)** **Supporting Materials** Unofficial Comment Form (Word) **(64)** VRF/VSL Justification **(65)** Mapping Document **(66)** Technical Rationale **(67)** Cost Effectiveness Background **(68)** Draft Reliability Standard Audit Worksheet (RSAW)	Additional Ballots and Non-binding Poll Updated Info **(69)** Info **(70)** Vote	09/05/18 - 09/14/18	Ballot Results TPL-001-5 **(71)** Implementation Plan **(72)** Non-binding Poll **(73)**	
	Comment Period Info **(74)** Submit Comments	07/30/18 - 09/14/18	Comments Received **(75)**	Consideration of Comments **(76)**
	Send RSAW feedback to: RSAWfeedback@nerc.net	09/13/18		

Draft 3 **TPL-001-5** Clean **(41)** | Redline to Last Approved(Updated 03/08/18) **(42)** | Redline to Last Posted **(43)** Implementation Plan Clean **(44)** | Redline to Last Posted **(45)** **Supporting Materials** Unofficial Comment Form (Word) **(46)** VRF/VSL Justification **(47)** Mapping Document **(48)** Technical Rationale (Updated 03/08/18) **(49)** Cost Effectiveness Background (Updated 03/08/18) **(50)**	TPL-001-5 Additional Ballot and Non-binding Poll Implementation Plan Initial Ballot Updated Info **(51)** Info **(52)** Vote	04/13/18 - 04/23/18	Ballot Results TPL-001-5 **(53)** Non-binding Poll **(54)** Implementation Plan **(55)**	
	Comment Period Info **(56)** Submit Comments	02/23/18 - 04/23/18	Comments Received **(57)**	Consideration of Comments **(58)**
Draft Reliability Standard Audit Worksheet (RSAW) Clean | Redline	Info Send RSAW feedback to: RSAWfeedback@nerc.net	03/30/18 - 04/23/18		
Draft 2 **TPL-001-5** Clean **(24)** | Redline to Last Approved **(25)** | Redline to Last Posted **(26)**	Initial Ballot and Non-binding Poll Updated Info **(34)** Info **(35)** Vote	10/13/17 - 10/23/17	Ballot Results **(36)** Non-binding Poll Results **(37)**	

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Supporting Materials
Unofficial Comment Form (Word) (29)
VRF/VSL Justification (30)

Mapping Document (31)
Technical Rationale (32)
Cost Effectiveness Background (33)

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Implementation Plan (19)

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Final Standards Authorization Request Clean **(13)**| Redline **(14)**				
Standards Authorization Request **(8)** **Supporting Materials** Unofficial Comment Form (Word) **(9)**	Comment Period Info **(10)** Submit Comments	05/26/16 - 06/24/16	Comments Received **(11)**	Consideration of Comments **(12)**
Standards Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)** Background Document - Order No. 754 Report **(5)**	Comment Period Info **(6)** Submit Comments	11/12/15 - 12/17/15	Comments Received **(7)**	
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	11/12/15 - 12/01/15		
The Standards Committee accepted the Standards Authorization Request on October 29, 2015				

Unoffical Nomination Form

Project 2015-10 Single Points of Failure – TPL-001 Standards Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Tuesday, December 1, 2015.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Documents and information about this project are available on the project page. If you have any questions, contact Standards Developer, Katherine Street (via email) or at (404) 446-9702.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the review or drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face drafting team meetings, as well as participate in all the team meetings held via conference calls.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team efforts is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2015-10 Single Points of Failure

The purpose of the proposed project is to draft a Standards Authorization Request (SAR) to address the findings of the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) assessment of protection system single points of failure, conducted in response to FERC Order No. 754,[1] including analysis of data from the NERC Rules of Procedure Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

[1] In Order No. 754, the Commission expressed its concern that there was an issue concerning the study of a single point of failure on protection systems. To address this issue, the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern. The Commission also directed NERC to submit an informational filing within six months explaining whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address it and what priority it should be afforded. *See Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 at PP 19-20 (2011).

As such, regarding single points of failure in protection systems, the SPCS and the SAMS proposed the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[2]

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Standards affected: TPL-001-4

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise with transmission planning in the United States and/or Canada.

Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Name:	
Organization:	

[2] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR or standard drafting team.

☐ Currently a member of the following SAR or standard drafting team(s):

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team.

☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ TRE	☐ NPCC	☐ SPP
☐ FRCC	☐ RFC	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:

☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users

☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[3] in which you have current or prior expertise:

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

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

Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

[3] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Standards Announcement

Project 2015-10 Single Points of Failure
Standard Authorization Request (SAR)

SAR Drafting Team Nomination Period Open through December 1, 2015

Now Available

Nominations are being sought for SAR drafting team members through **8 p.m. Eastern, Tuesday, December 1, 2015**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in the drafting team meetings if appointed by the Standards Committee. If appointed, you are expected to attend most of the face-to-face team meetings, as well as participate in all the team meetings held via conference calls.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the team sets forth. Drafting teams also will have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the drafting team efforts is outreach. Members of the team should be conducting outreach during development prior to posting to ensure all issues can be discussed and resolved.

Previous drafting team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included on the project page and the nomination form.

Next Steps

The Standards Committee is expected to appoint members to the team in December 2015. Nominees will be notified shortly after they have been appointedt.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Katherine Street (via email) or at (404) 446-9702.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)		
Date Submitted:	October 05, 2015		
SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standards		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

SAR Information

As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:
 	
• For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
   ▪ Replace "relay" with "component of a Protection System," and
   ▪ Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
• For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
   ▪ Remove the phrase "or a relay failure[13]" from items a, b, c, and d to create distinct events only for stuck breakers.
   ▪ Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure[13]" with "a component failure of a Protection System[13]."
• Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
• Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

[1] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to appoint a Standard Drafting Team (SDT) to address recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request.”
Identify the Objectives of the proposed standards’ requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and Results-based Reliability standards to address the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request.”
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request,” and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard’s requirements and measures.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to address the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request.” The SDTs execution of this SAR would, in addition, consider retirements to requirements under Paragraph 81 criteria. The SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” is incorporated in its entirety into this SAR, so as not to unnecessarily repeat or paraphrase the substance report.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.

Reliability Functions		
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Unofficial Comment Form

Project 2015-10 Single Points of Failure – TPL-001

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2015-10 Single Points of Failure Standard Authorization Request (SAR)**. Comments must be submitted by **8 p.m. Eastern, Thursday, December 17, 2015**.

Documents and information about this project are available on the project page. If you have questions, contact Katherine Street (via email) or by telephone at (404)-446-9702.

Background Information

This posting is soliciting informal comment on the SAR.

The purpose of the proposed project is to draft a SAR to address the findings of the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) assessment of protection system single points of failure, conducted in response to FERC Order No. 754,[1] including analysis of data from the NERC Rules of Procedure Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

As such, regarding single points of failure in protection systems, the SPCS and the SAMS proposed the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace “relay” with “component of a Protection System,” and
  - Add superscript “13” to reference footnote 13 for the replaced term under the “Category” column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase “or a relay failure” from items a, b, c, and d to create distinct events only for stuck breakers.

[1] In Order No. 754, the Commission expressed its concern that there was an issue concerning the study of a single point of failure on protection systems. To address this issue, the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore this reliability concern. The Commission also directed NERC to submit an informational filing within six months explaining whether there is a further system protection issue that needs to be addressed and if so, what forum and process should be used to address it and what priority it should be afforded. *See Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 at PP 19-20 (2011).

    - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing “a relay failure” with “a component failure of a Protection System.”
- Replace footnote 13 in TPL-001-4 with, “The components from the definition of “Protection System” for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.”[2]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

Questions

1. Do you agree with the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, **provide specific language revisions that would make it acceptable to you**.

   ☐ Yes
   ☐ No
   Comments:

2. If you have any other comments on this SAR that you haven’t already mentioned above, please provide them here:

   Comments:

[2] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

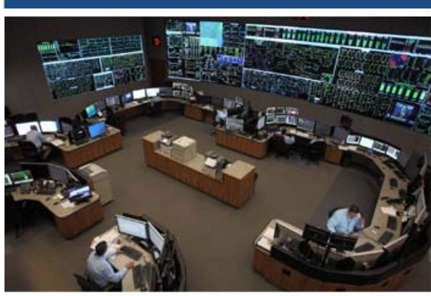
Order No. 754

Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request

System Protection and Control Subcommittee (SPCS) and
System Modeling and Analysis Subcommittee (SAMS)

September, 2015

RELIABILITY | ACCOUNTABILITY

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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to ensure the reliability of the bulk power system (BPS) in North America. NERC develops and enforces NERC Reliability Standards;[1] annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission ("FERC" or "Commission") and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into several assessment areas within the eight Regional Entity (RE) boundaries, as shown in the map and corresponding table below.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
TRE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

[1] Capitalized terms include, but are not limited to the Glossary of Terms Used in NERC Reliability Standards. March 3, 2015. (http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf) and Definitions Used in the NERC Rules of Procedure (ROP), Appendix 2. July 1, 2014. (http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_2_ROP_Definitions_20140701_updated_20140602.pdf).

Executive Summary

This report provides the results of an assessment of protection system single points of failure (SPF) in response to FERC Order No. 754,[2] including analysis of data from the NERC Section 1600 Request for Data or Information. Based on the analysis of data received, the report provides a discussion of alternatives to address this reliability concern and recommends a course of action to address the concern using a risk-based method.

Nearly 4,000 buses energized above 100kV were examined in detail. This is a comprehensive set of the key buses in the Bulk Electric System. This assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Regarding single points of failure in protection systems, the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) considered a variety of alternatives, and concluded that the most appropriate recommendation that aligns with O754 directives and maximizes reliability of protection system performance is to modify NERC Reliability Standard TPL-001-4 (*Transmission System Planning Performance Requirements*) through the NERC standards development process defined in the NERC Rules of Procedure. The recommended modifications address specifics of Protection System component failure, aspects of steady state and stability performance testing, and expansion of extreme event assessment requirements in order to minimize the potential risk of SPFs. Chapter 2 contains a discussion of alternatives considered. Specific guidance for modifying NERC Reliability Standard TPL-001-4 is provided in Chapter 3.

[2] *Interpretation of Transmission Planning Reliability Standard*, Order No. 754, 136 FERC ¶ 61,186 (2011) ("Order No. 754") (http://www.ferc.gov/whats-new/comm-meet/2011/091511/E-4.pdf).

Introduction

Objective

The objective of this assessment is to determine whether there is a reliability concern that NERC should address regarding the study of single points of failure on protection systems and, if so, what forum and process should be used to address the issue. This report provides the results of a comprehensive assessment of the study of data from the NERC Section 1600 Request for Data or Information collected in response to FERC Order No. 754. Based on the analysis of data, there is some degree of elevated reliability risk from SPF in certain key instances. The report provides discussion of alternatives to address this reliability concern and recommends a course of action to address the concern using a risk-based method.

Background

The issue of protection system failures brought to the forefront potential reliability concerns in Requirement R1.3.10 of the NERC transmission planning Reliability Standard TPL-002-0b (*System Performance Following Loss of a Single Bulk Electric System Element (Category B)*). The concern relevant to this assessment is whether Requirement R1.3.10 requires the study of protection system failures as part of Category B disturbances.

In FERC Order No. 754, issued September 15, 2011, the Commission agreed with commenters that this issue does not have to be addressed in TPL-002-0b, Requirement R1.3.10. However, the Commission also stated their belief that there is "an issue concerning the study of the non-operation of non-redundant primary protection systems; e.g., the study of a single point of failure on protection systems."[3] To address this concern, the Commission directed FERC staff to meet with NERC and its appropriate subject matter experts to explore the reliability concern, including where it can best be addressed, and identify any additional actions necessary to address the matter.

To satisfy the directive, a FERC Technical Conference was held October 24–25, 2011, to facilitate an open exchange among FERC staff, NERC staff, and industry stakeholders. One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing whether single points of failure in protection systems pose a reliability concern. NERC staff worked with the SPCS and SAMS to develop a request for data or information under Section 1600 of the NERC Rules of Procedure[4] (the "Data Request" or "Order No. 754 Data Request"). The NERC Board of Trustees approved the Data Request on August 16, 2012.

The responsible Functional Entities ("entities") have submitted data to NERC for buses operated at 100 kV and above. Data is presented in Appendix A of this report according to voltage range (100–199 kV, 200–299 kV, 300–399 kV, 400–599 kV, and 600 kV or higher). The SPCS and SAMS have reviewed the submitted data, which provides statistical information on the number of buses at which a protection system single point of failure could result in an adverse impact to reliability of the bulk power system. The data also indicates the extent to which exposure to single points of failure exists at these buses, broken down by specific component categories of a protection system.

The assessment of this data set forms the basis for identifying the risk associated with protection system single points of failure, development of alternatives to address associated concerns, and subsequently a recommendation of the preferred alternatives to address the associated concerns.

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[3] Id. at P.19.

[4] (http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20140701_updated_20140602%20(updated).pdf

Chapter 1 – Analysis of Data

Order No. 754 Data Request

Overview

The Order No. 754 Data Request[5] required that Transmission Planners, working with the Generator Owners, Transmission Owners, and Distribution Providers within their transmission planning areas, assess their portion of the Bulk Electric System (BES) for locations at which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk. To accomplish this task in an effective and efficient manner, the SPCS and SAMS developed a method that entities could follow to create the statistics associated with this Data Request. Entities were permitted to use an alternate method, including combining steps, skipping steps, or reordering steps, to minimize burden based on their particular circumstances, and could use information from existing studies and existing assessments of protection systems in developing responses to the data request. For example, TPL-004-0a (*System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)*) simulations from transmission planning assessments could be used in developing responses to the Data Request.

Entities that followed an alternate method or utilized existing studies and existing assessments of protection systems in developing responses were required to provide a complete subset of buses containing both of the following characteristics:

- The bus has at least one Element for which the protection system does not fully meet the redundancy attributes for all component categories of Table B (from the data request), "Protection System Attributes
- Planning studies simulating a three phase fault, show that clearing times resulting from a single point failure of at least one protection system on an Element connected to that bus will result in system performance exhibiting one of the adverse impacts identified in Table C (from the data request), "Performance Measures."

The process of using differing methodologies to obtain this list of buses results in inconsistencies in the specific numbers of Protection Systems and buses evaluated in the various tables of Protection System attributes.

The Data Request included criteria to limit the assessment to a sample of buses using qualitative criteria that identified and included the buses more likely to have a more significant stability impact on the bulk power system. See Table 1.1 below, which is Table A from the Data Request.

[5] Request for Data or Information: Order No. 754 Single Point of Failure on Protection Systems, August 16, 2012.

Table 1.1: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses operated at 100 kV or higher that directly supply off-site power to a nuclear generating station
Any additional buses operated at 100 kV or higher that the Transmission Planner believes are necessary for the reliable operation of the bulk power system

For the buses meeting the Table 1.1 criteria, the Transmission Planner assessed the system performance for a three-phase fault accompanied by a protection system failure. For the purposes of the Data Request, Transmission Planners were to simulate clearing, based on the remote protection that would operate for the bus fault. The Transmission Planners were not to simulate operation of any local protection with the exception of local breaker failure protection (where provided) in instances where a single trip coil was the only single point of failure for protection systems on all Elements connected to the bus. In these cases, operation of the breaker failure protection was allowed in the simulation.

Following simulation of the events described above, the Transmission Planner evaluated the system performance against criteria provided in the Data Request that the SPCS and SAMS believe are indicative of the potential for instability, uncontrolled separation, or cascading outages. The criteria are contained in Table 1.2 below, which is Table C from the Data Request.

Table 1.2: Performance Measures
1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2. Loss of synchronism between two portions of the system
3. Negatively damped oscillations

For buses where the simulated system performance exhibited one or more of the adverse system response characteristics in Table 1.2, the protection system owners (Generator Owners, Transmission Owners, and Distribution Providers owning the relevant protection systems) provided detailed information regarding the protection systems on all elements connected to the bus. The presence of single points of failure was then assessed at the component level of a protection system, which consists of protective relays, communication systems, AC current and voltage inputs, and DC control circuitry. It should be noted that in some instances stability simulations were conducted prior to any review of the actual applied Protection Systems, while in other instances, the protection system owners may have conducted a preliminary assessment of the initial list of buses prior to simulations being conducted. Protection system owners evaluated the components of a protection system against the attributes defined in Table 1.3 below, which is Table B from the Data Request.

Table 1.3: Protection System Attributes to be Evaluated
Protective Relays: The protection system includes two independent protective relays that are used to measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal condition.
Communication Systems: The protection system includes two independent communication channels and associated communication equipment when such communication between protective relays for communication-aided protection functions (i.e., pilot relaying systems) is needed to satisfy system performance required in NERC Reliability Standards TPL-002-0b and TPL-003-0a.
AC Current and Voltage Inputs: The protection system includes two independent AC current sources and related inputs, except that separate secondary windings of a free-standing current transformer (CT) or multiple CTs on a common bushing can be used to satisfy this requirement; and includes two independent AC voltage sources and related inputs, except that separate secondary windings of a common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device can be used to satisfy this requirement.
DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC distribution panel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).

Data was collected separately for the station DC supply. This data was collected on DC supplies to all of the 3,916 buses that meet the Table A criteria. Station DC supply data was collected to assess the incidence of two station DC supplies as well as the level of monitoring for buses with only one station DC supply. See the station DC supply attributes to be reported in Table 1.4 below, which is Table D from the Data Request.

Table 1.4: Station DC Supply Attributes to be Reported
The protection system includes two independent station DC supplies
The protection system includes one station DC supply that is centrally monitored; if the station DC supply is a battery the monitoring includes alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is centrally monitored; the station DC supply is a battery and the monitoring does not include alarms for both low voltage and a battery open condition
The protection system includes one station DC supply that is not centrally monitored

Entities submitted data in a tabular format as described in the Data Request. The output of the collected data is collated in the following eight tables (see Appendix A).

- Table A.1 – Buses Evaluated by the Transmission Planner
- Table A.2 – Attributes of Evaluated Transmission Line Protection Systems
- Table A.3 – Attributes of Evaluated Transmission Transformer Protection Systems
- Table A.4 – Attributes of Evaluated Generator Step-Up Transformer Protection Systems
- Table A.5 – Attributes of Evaluated Step-Down Transformer Protection Systems
- Table A.6 – Attributes of Evaluated Shunt device Protection Systems
- Table A.7 – Attributes of Evaluated Bus Protection Systems
- Table A.8 – Station DC Supply Attributes

The data for each table, aggregated for all responding entities across North America, is presented in Appendix A. Row 4 of Table A.1 contains the subset of buses that contain at least one Protection System where a failure to trip due to an existing single point of failure would result in one of the performance issues listed in Table 1.2. The data in Tables A.2 through A.7 are dependent on the methodology used by the reporting entity in identifying the buses in Row 4 of Table A.1. The assessment in this report is based on extensive discussion recognizing the variability of the data. The SPCS and SAMS have recognized this variability in the following discussion of the data. While in some cases this variability prevents definitive quantitative statements, the SPCS and SAMS consider the data to be sufficient to draw valid conclusions based on a qualitative but technical assessment.

Table A.1: Buses Evaluated by the Transmission Planner

The data in Table A.1 provides general insight regarding the buses evaluated by the Transmission Planners and includes the following information for each voltage range:

1. the total number of buses,
2. the number of buses that met the Table 1.1 criteria (Data Request, Table A) for further review,
3. the number of buses that were evaluated using actual clearing times
4. the number of buses for which a simulation based on actual clearing times exhibited at least one of the adverse impacts in Table 1.2 (Data Request, Table C).

Table A of the Data Request included the criteria shown in Table 1.1 to focus the analysis on those buses more likely to have a significant impact on the stability of the bulk power system. Limiting the number of buses significantly reduced the effort required of responding entities while still providing NERC a data population sufficient to draw valid conclusions. The criteria in Table 1.1 included the number of circuits connected to the bus, whether the bus directly supplies off-site power to a nuclear generating station, and whether the Transmission Planner believes for any other reason that the bus is necessary for the reliable operation of the bulk power system. For the purpose of applying the Table 1.1 criteria, the number of circuits connected includes any elements that represent a significant source of fault current (i.e., transmission lines, transmission transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher, and generator step-up transformers connecting generating resources with aggregate gross nameplate rating greater than 20 MVA). These criteria resulted in a large enough sample of data to draw valid conclusions. This conclusion is based on both the number and percentage of buses in each voltage range that met the criteria in Table 1.1. At the high-voltage (HV) levels (up to 230 kV), entities tested over 1,000 buses in each voltage range. At the extra high-voltage (EHV) levels (greater than 230 kV), entities tested over one-half of the total number of buses.

The reporting entities identified the following numbers of buses meeting the requirements of Table A in the data request:

- 1,522 buses (7 percent of all buses) operated at 100–199 kV,
- 1,310 buses (34 percent of all buses) operated at 200–299 kV,
- 768 buses (57 percent of all buses) operated at 300–399 kV,
- 262 buses (67 percent of all buses) operated at 400–599 kV, and
- 54 buses (81 percent of all buses) operated at 600 kV and above.

Table 1.5: Buses Evaluated by the Transmission Planner

Row	Description	100-199 kV	200-299 kV	300-399 kV	400-599 kV	≥600 kV
1	Total number of buses in the transmission planning area	21,817	3,848	1,350	392	67
2	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	1,522	1,310	768	262	54
	Percentage of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	7%	34%	57%	67%	81%

In general, the short-circuit strength at a bus is indicative of the potential risk that a prolonged fault will impact reliable operation of the bulk power system. Therefore, on a qualitative basis, the set of buses that met the criteria in Table A is more likely to include buses at which a protection system single point of failure may result in an adverse impact to reliability of the bulk power system than the buses with fewer connected circuits.

Rows 3 and 4 of Table A.1 provide information on the number of buses evaluated based on maximum expected clearing times and the number of buses at which simulation of a three-phase fault and a protection system single point of failure indicate system performance that exhibits at least one of the adverse impacts in Table 1.2 of the Data Request. The adverse impacts are indicative of a risk to reliable operation of the bulk power system and include the following:

- loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern or Western Interconnections, or 1,000 MW or more in the ERCOT or Québec Interconnections,
- loss of synchronism between two portions of the system, and
- negatively damped oscillations.

Although various equivalent methodologies were allowed, the data in Row 4 is essentially the number of buses with both a Table C performance issue and the presence of a Protection System with a single point failure issue. This may overstate the problem somewhat, as not all SPF result in a failure to trip, and that many SPF will result in actual clearing times that are less than those resulting from a bus fault. Never the less, viewing the data in rows 3 and 4 of Table 1.6 in relation to each other demonstrates that, in general, the probability that a failure of a protection system to clear a fault will impact reliable operation exists and increases at higher voltages as shown in the table.

Table 1.6: Buses Evaluated by the Transmission Planner						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
3	Total number of buses evaluated by the Transmission Planner based on actual clearing times	716	813	356	164	44
4	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, “Performance Measures”	160	316	212	101	43
	Percentage of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, “Performance Measures”	22%	39%	60%	62%	98%

However, this information alone does not indicate a reliability concern. Assessment of this reliability concern is a function of both the potential consequence and the exposure to a single point of failure. Thus, it is necessary to analyze the Table A.1 data in conjunction with the protection system attributes data in Tables A.2–A.7.

Tables A.2–A.7 Data: Attributes of Evaluated Protection Systems

Data in Tables A.2–A.7 provides insight into the presence of single points of failure for various power system elements (transmission lines, transmission transformers, generator step-up transformers, step-down transformers, shunt devices, and buses). These tables provide information on the total number of protection systems evaluated, the number that contain a single point of failure, and the presence of single points of failure by components of a protection system: protective relays, communication systems, AC current and voltage inputs, and DC control circuitry (see Table 1.3). The data collected in Tables A.2-A.7 for DC control circuitry includes auxiliary relays and trip coils but excludes the station DC supply. Data for the station DC supply was collected separately in Table A.8.

The single points of failure reported in Tables A.2–A.7 are related to the buses at which the Transmission Planner identified a potential risk, based on simulation of a three-phase fault and protection system single point of failure using maximum expected clearing times. In developing the requested data, simulations performed by the Transmission Planners were based on the assumption that a component failure of a protection system associated with a single point of failure would, in all cases, result in a failure to trip. This assumption provided a conservative and uniform method for simulating faults. However, the impact of a single component failure will not always result in a protection system failure to trip, depending on the component that fails and the design of the overall protection system. This subject is discussed further for each component type in the following subsections of this report. The discussion of component types is arranged according to the perceived risk to reliability associated with a single point of failure, based on the experience of the SPCS and SAMS members. Technical analysis relative risk of various categories of failure is included in the next section of this chapter.

DC Control Circuitry

A single point of failure in DC control circuitry will result in the failure of a given protection system to trip and, depending on its design and the location of the failure, may also result in a failure to initiate breaker failure protection.

As discussed at the 2011 FERC Technical Conference on single points of failure, the single point of failure concern originated in a NERC Alert[6] based on the negative outcomes of three significant events. The root cause of these three events was the failure of a single relay (an auxiliary relay or lockout relay). Auxiliary relays and lockout relays are included in the DC control circuitry protection system attribute. These relays are generally unmonitored devices and, thus, may fail and remain undetected until they are periodically tested. Auxiliary relay failures in designs that include use of a single auxiliary relay for multiple functions will result in prolonged fault duration, particularly where a single auxiliary relay is used for both tripping and breaker failure initiation.

Protective Relays

A single point of failure of a protective relay poses a similar exposure to prolonged fault duration as that of failure of a DC control circuit; however, the risk depends on the relay type and protection system design. Many protection system designs using electromechanical relays are configured such that a failure of one relay will be backed up to some degree by other relays (i.e., an electromechanical protection system design is typically is made up of multiple relays and more than one may respond to a given fault). Similar to an auxiliary relay, an electromechanical relay may fail and the failure may remain undetected until the relay is tested. On the other hand, microprocessor relay may be monitored through an entity's supervisory control and data acquisition (SCADA) system; thus, most failure modes can be detected and addressed, in which cases the risk to the system is reduced to a relatively short period of time.

Communication Systems

A single point of failure in a communication system poses a lower level of risk. The Data Request only analyzed communication equipment in protection systems where communication-aided protection is needed to satisfy the system performance required in NERC Reliability Standards. The risk associated with a given protection system is dependent on the protection system design. Depending on the protection system design, a single point of failure may result in a failure of the communication-aided system to initiate a high-speed trip (e.g., a permissive overreaching transfer trip scheme), in which case delayed tripping will occur. In other designs, a communication system failure will not prevent high-speed tripping (e.g., a directional comparison blocking scheme).

Communication systems, regardless of vintage or design, are typically monitored and alarmed via SCADA or tested periodically.

AC Current and Voltage Inputs

A single point of failure in AC current and voltage inputs poses a lower level of risk of failure to trip. Instrument transformers are generally more robust than the other components of a protection system analyzed in the Data Request. However, cable runs, fuses, and terminations have a similar susceptibility to failure as DC control circuitry.

In most cases, a current circuit failure will result in an imbalance, which may result in a trip. In differential or ground overcurrent applications on transmission lines, buses, transformers, or shunt devices, AC current input

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[6] Industry Advisory, Protection System Single Point of Failure, March 30, 2009. (http://www.nerc.com/fileUploads/File/Events%20Analysis/A-2009-03-30-01.pdf).

failure will typically cause a circuit to trip at a certain load or fault level. Additionally, where AC current input circuits are monitored via SCADA, loss of a current input may be identified by automated devices or dispatch personnel.

Most microprocessor relays alarm for a loss of potential via SCADA; thus, the time that failed equipment is connected to the system can be minimized. Most electromechanical relays that use voltage inputs are prone to tripping on loss of a single-phase voltage (the most common AC voltage input failure). Additionally, where AC voltage input circuits are monitored via SCADA, low voltage due to a circuit failure may be alarmed.

Overall Order 754 Data Interpretation

Below 600kV, simulated testing showed that the probability of a three-phase fault accompanied by a protection system failure could result in the adverse system impacts listed in Table 1.2. The probability of an adverse impact decreased as the voltage class was lowered. At these voltage levels, a significant percentage of protection systems included single points of failure. This data shows that the chance of an adverse system impact due to a single point of failure at buses as low as 100kV exists, and leads to the conclusion that some risk mitigating action must be taken.

Above 600kV, simulated testing showed that the probability of a three-phase fault accompanied by a protection system failure resulting in an adverse system impact was high. However, almost all protection system equipment was fully redundant at that voltage level. The data shows that the chance of an adverse system impact due to a single point of failure at 600 kV and above is low.

Chapter 2 – Alternatives

The SPCS and SAMS considered the following alternatives in order of preference for addressing reliability risks associated with single points of failure:

Standards Development Process

Modify Reliability Standard TPL-001-4 – Transmission System Planning Performance Requirements

- Modify footnote 13 to include, at a minimum, protective relays, DC control circuitry, and station DC supply
- Place additional emphasis on assessment of a three-phase fault and protection system failure
  - Keep as an extreme event, but require studies of instances of single points of failure
    - Provides assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated
  - Elevate to a planning event with its own system performance criteria
    - Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event
  - Keep as an extreme event with no change (other than footnote 13)
    - Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments
- Include a Guidelines and Technical Basis section related to the revisions pertaining to the study of protection system failures

Create a New Standard Addressing the Study of Protection System Single Points of Failure

- Remove relay failure from TPL-001-4 and create a separate TPL (transmission planning) or PRC (protection and control) standard on the study of protection system single points of failure (including the same options as the previous alternative)
  - Accomplishes same objective as modifying TPL-001-4
  - Retaining in TPL-001 is more efficient and keeps all planning tests in one standard (i.e., reason for combining TPL-001 through TPL-004)

Create a New Standard Requiring Redundant Protection Systems on BES Elements

- Create protection system redundancy PRC standard requiring redundant protection systems for all BES Elements
  - Not an efficient way to address the problem (precludes other solutions)
  - Promotes a zero-defect approach rather than a risk-based approach

Reliability Guideline

- Provides insight into modeling protection system failures in planning assessments
- Provides insight into evaluation of risk of a single point of failure

- Does not provide assurance a three-phase fault with protection system failure is studied in all planning assessments

NERC Alert

- Raises awareness based on findings from the Data Request
- Does not provide assurance a three-phase fault with protection system failure is studied in all planning assessments

Chapter 3 – Conclusion

Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists). Not all failures adversely affect reliable operation of the bulk power system. The reliability risk varies based on which component of a protection system fails.

Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: 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.

Any modifications to a NERC standard must be made through the NERC Standards Process under the NERC rules of Procedure. Regarding single points of failure in protection systems, the SPCS and SAMS make the following recommendations to a Standards Drafting Team that may be formed for modifying TPL-001-4.:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure[13]" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure[13]" with "a component failure of a Protection System[13]."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[7]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

[7] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

Appendix A – Order No. 754 Data

Table A.1: Buses Evaluated by the Transmission Planner						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of buses in the transmission planning area	21,817	3,848	1,350	392	67
2	Total number of buses in the transmission planning area that meet the criteria in Table A, "Initial Criteria for Buses to be Tested"	1,522	1,310	768	262	54
3	Total number of buses evaluated by the Transmission Planner based on actual clearing times	716	813	356	164	44
4	Total number of buses evaluated by the Transmission Planner based on actual clearing times that resulted in system performance exhibiting any adverse impact defined in Table C, "Performance Measures"	160	316	212	101	43

Table A.2: Attributes of Evaluated Transmission Line Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of transmission line terminals at which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	2,227	1,799	1,625	402	182
2	Number of transmission line terminals at which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	1,190	996	227	270	12
3	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the protective relays	229	25	4	0	0
4	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the communication systems	364	301	42	7	0
5	Number of transmission line terminals at which the protection systems does not meet the specified protection system attributes for the AC current and voltage inputs	960	581	182	99	12
6	Number of transmission line terminals at which the protection system does not meet the specified protection system attributes for the DC control circuitry	785	642	42	205	0

Table A.3: Attributes of Evaluated Transmission Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of Transmission Transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	382	519	559	129	87
2	Number of transmission transformers for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	186	297	188	63	3
3	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the protective relays	66	92	121	12	3
4	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	81	135	33	3	3
5	Number of transmission transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	143	260	131	51	0

Table A.4: Attributes of Evaluated Generator Step-Up Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of generator step-up transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	251	315	167	52	29
2	Number of generator step-up transformers for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	127	151	27	16	0
3	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the protective relays	68	66	12	4	0
4	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	79	60	15	1	0
5	Number of generator step-up transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	107	118	13	13	0

Table A.5: Attributes of Evaluated Step-Down Transformer Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of step-down transformers for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	345	182	32	11	0
2	Number of step-down transformers for which the protection system does not meet all of the specified protection system attributed s for redundancy in Table B	211	101	16	5	0
3	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the protective relays	62	25	6	4	0
4	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	134	53	2	0	0
5	Number of step-down transformers for which the protection system does not meet the specified protection system attributes for the DC control circuitry	165	88	14	1	0

Table A.6: Attributes of Evaluated Shunt Device Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of shunt devices for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	205	151	142	66	114
2	Number of shunt devices for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	90	83	38	48	0
3	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the protective relays	65	19	5	8	0
4	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	71	44	12	3	0
5	Number of shunt devices for which the protection system does not meet the specified protection system attributes for the DC control circuitry	86	64	29	43	0

Table A.7: Attributes of Evaluated Bus Protection Systems						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Total number of buses for which protection system attributes were evaluated by the Generator Owners, Transmission Owners, and Distribution Providers	642	565	516	126	45
2	Number of buses for which the protection system does not meet all of the specified protection system attributes for redundancy in Table B	403	370	220	36	3
3	Number of buses for which the protection system does not meet the specified protection system attributes for the protective relays	342	268	188	8	2
4	Number of buses for which the protection system does not meet the specified protection system attributes for the AC current and voltage inputs	276	246	47	13	1
5	Number of buses for which the protection system does not meet the specified protection system attributes for the DC control circuitry	340	263	54	35	0

Table A.8: Station DC Supply Attributes						
Row	**Description**	**100-199 kV**	**200-299 kV**	**300-399 kV**	**400-599 kV**	**≥600 kV**
1	Number of buses for which the station DC supply includes two independent DC supplies	548	528	590	154	54
2	Number of buses for which the station DC supply includes one DC supply that is centrally monitored, and if the station DC supply is a battery, includes alarms for both low voltage and a battery open condition	234	179	37	13	0
3	Number of buses for which the station DC supply includes one DC supply that is centrally monitored, the station DC supply is a battery, and the monitoring does not include alarms for both low voltage and a battery open condition	657	489	95	35	0
4	Number of buses for which the station DC supply includes one DC supply that is not centrally monitored	51	33	3	2	0

Note: The data in Table A.8 was collected on DC supplies for all of the 3,916 busses meeting the requirements of Table A in the data request. These are the buses in Row 2 of Table A.1.

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Current Option (Draft 3):

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known -outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**1.1.6.** Resources (supply or demand side) required for Load.

Option considered for Draft 3:

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. ~~These~~ This outage coordination~~s~~ ~~are~~ is required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Previous Option (Draft 2)

1.1.2 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.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The SDT did not feel like a time duration alone would capture "significant outages". Additionally, the language allows PC's to develop a process for selecting "significant outages" to be studied in the Near-Term Transmission Planning Horizon.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure13" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure13" with "a component failure of a Protection System13."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Revision By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and

- Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.

- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language.

Current Option Footnote 13 (Draft 3)

1. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
   - A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
   - 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 at a Control Center;
   - A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
   - A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Previous Option Footnote 13 (Draft 2)

The previous option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. 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;

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

c. 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;

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

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team added clarifications to the previous draft option which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

Extreme Events and P8 Category:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754, Section 1600 data collection and report indicated a risk to the BES for three phase faults followed by single points of failure of a protection system. Therefore, the SDT decided to make Category P8 planning event if a three-phase fault following by a single points of failure resulted in Cascading or instability.

Revision By Standard Drafting Team to Satisfy FERC Order

Current Option (Draft 3):

~~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. 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.

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 implementationList System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~

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

Previous Option (Draft 2):

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

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

Standard Drafting Team Proposal

The standard drafting team feels that there is a reliability risk to the BES if Cascading or instability results in a three-phase fault followed by single point of failure of a protection system. There was confusion in the industry with the language that was similar to a CAP but not exactly a CAP. Therefore, the standard drafting team decided to create a P8 planning event which required a CAP if Cascading or instability occurs.

Survey Report

Survey Details

Name 2015-10 Single Points of Failure SAR

Description

Start Date 11/12/2015

End Date 12/17/2015

Associated Ballots

Survey Questions

1. Do you agree with the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

Yes

No

2. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.

Responses By Question

1. Do you agree with the scope and objectives of the SAR? If not, please explain why you do not agree and, if possible, provide specific language revisions that would make it acceptable to you.

Kevin Conway - INTELLIBIND - 5 - NA - Not Applicable

Selected Answer: Yes

Answer Comment:

None

Document Name:

Likes: 0

Dislikes: 0

Guy V. Zito - Northeast Power Coordinating Council - 10 -

Selected Answer: No

Answer Comment:

NPCC suggests that while the TPL-001-4 standard is being revised to address single component failure, the SAR is revised to also address a point of confusing regarding testing for line end open conditions which may result in a RFI if not addressed here. Specifically TPL-001-4, footnote 7 states “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”

1) Does this mean opening one end of a line section with a breaker operation?

2) For line section connected to a station with a breaker and a half or ring bus design, only one breaker would be opened?

3) Using a Disconnect Switch is or is not applicable for this event?

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

MH believes the proposed SAR did not completely capture the recommendations proposed in the background NERC document posted in the project page. The SAR recommends to simply replace the “relay” with “components of protection system” and to replace foot note 13 with the definition of “Protection System” under Categary-5 in Table-1 of TPl-001-4. The category P5 in Table-1 of TPL-001-4 recommends simulating a single-line-to-ground (SLG) fault, but the proposed SAR is recommending to modify the section 4.5 of the TPL standard to simulate a three-phase fault (simulation of a three-phase fault is proposed by NERC SPCS and SAMS in their background document)

Based on the background document from SPCS and SAMS, it appears that a breaker with a single trip coil is OK from a redundancy point of view if it is the only single point of failure and can be simulated as a breaker failure event. A risk based assessment should be used to identify locations of concern rather than making full protection redundancy a bright line requirement (such as all stations 100 kV and above). The background document provided a criteria for busses to be evaluated (Table 1.1) and criteria to evaluate the system performance (Table 1.2). These ideas don’t seem to be in the SAR.

MH is proposing to introduce a separate category (or to modify Category P5) in Table 1 of TPL-001-4 to simulate a three-phase fault only for the busses meeting the criteria in Table 1.1 in the NERC background document and to evaluate the system performance against the criteria given in Table 1.2.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - WECC,NPCC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	WECC,NPCC

Selected Answer: No

Answer Comment:

PSEG provides input below suggesting improvements to several parts of the SAR.

1. **Section entitled "Industry Need (What is the industry problem this request is trying to solve?)"** This section is too detailed. The project's webpage should have the final Order 754 Section data request posted in addition to the presently posted September SCPS/SAMs report and should have links to both documents. It should state that the SAR is a product of both documents – the Section 1600 data request and the SCPS and SAMS report which analyzed the results of that data request and developed recommendations and conclusions. The SAR need not repeat those recommendations and conclusions in the SAR itself.

2. **Section entitled "Purpose or Goal (How does this request propose to address the problem described above?)"** The present language limits the SDT to making recommendations identified in the SPCS and SAMS report. While such recommendations may be considered by the SDT, the SAR should not prevent the SDT from making

recommendations that differ from those in the SCPS and SAMS report. With this in mind, the following purpose statement is offered for consideration:

The primary goal of this SAR is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) for the purpose of clarifying which Protection System components shall be included within the single point of failure analyses required by this Standard. The SDT shall give due weight to and consideration of the recommendations in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request."

3. Section entitled "Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?)" This section has limitations that are similar to the prior sections. Again, the language should no limiting the SDT's work product to the modifications recommended in the SCPS and SAMS report. The following language is offered for consideration.

Provide clear, unambiguous requirements and results-based Reliability standards to address the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) that achieve the primary goal in the preceding section."

4. **Section entitled "Brief Description (Provide a paragraph that describes the scope of this standard action.)"** No comments.

5. **Section entitled "Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)"** We recommend one word change to the first sentence which further supports the Purpose and Goal section as modified above:

The SDTs execution of this SAR requires the SDT to [address - strike "**address"** and replace with "**consider"**] the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request."

Document Name:

Likes:	0
Dislikes:	0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: No

Answer Comment:

South Carolina Electric and Gas agrees with The SERC Planning Standards Subcommittee below:

"The original Order 754 work was based on a selection of a subset of transmission buses (the larger stations), rather than the entire BES. There does not appear to be anything in the SAR which limits the scope of the applicability in a similar fashion. We are concerned about the potential for inadvertently drastically increasing assessment work load if the scope is not appropriately limited. "

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: No

Answer Comment:

Drop the “Modify TPL-001-4 (Part 4.5)” item from the SAR. The existing Part 4.5 text already includes the obligation to consider all (i.e. item number 1 and item number 2) of the stability extreme event items in Table 1. There is no need to add more text to make duplicative reference to item number 2.

Consider adding other items to the scope of the SAR to address several specific deficiencies that have been found in the TPL-001-4 standard.

- **Table 1, Header note i** – Revise note i because the present text can be interpreted to contradict the NERC Definition for Non-Consequential Load Loss. The response of voltage sensitive load and load disconnected from the System by end-user equipment are not Non-Consequential Load Loss. So by definition, response of voltage sensitive load and load disconnected from the System by end-user equipment are excluded from the steady state Non-Consequential Load Loss Allowed performance requirement. Wording like, “. . . associated with a planning event is allowed” may be clearer and not contradictory.
- **Cascading clarification** – Clarify the understanding the NERC definition of Cascading (e.g. Table 1, header note a). The subsequent loss of system elements, load, or generation is classified as Cascading when it results in widespread electric service interruption. Therefore, the loss of line circuits, transformer circuits, generators, or limited amounts of load due to cascading does not qualify as exceeding the Cascading performance requirement.
- **Load loss due to cascading** – Address the treatment of load loss due to cascading - perhaps with an additional Table 1 footnote. Load loss due to cascading does not meet the NERC definition of either Consequential Load Loss or Non-Consequential Load Loss. So, cascading load loss does not apply to the Non-Consequential Load Loss Allowed performance requirement. However, an additional performance requirement should probably be added that the sum of cascading load loss and Non-Consequential Load Loss should not exceed an entity’s IROL criteria.
- **Use of sensitivity cases in extreme event analysis** – Revise the wording in R3 and R4 (e.g. referring to Part 2.1 or Part 2.4 without limiting the obligation to planning event studies) to remove the obligation to use sensitivity cases in extreme event studies (i.e. R3.2 and R4.2). Extreme event studies using baseline cases (R2.1.1, R2.1.2, R2.2.1, R2.4.1, and R2.4.2) are essentially probing studies that consider extraordinary contingencies. Extreme event studies using sensitivity cases (R2.1.4 and R2.4.3) are essentially probing studies that consider the compounded effect of both extraordinary contingencies and extraordinary system conditions. The obligation to perform these compound effect studies results in an unreasonable expenditure of resources compared to the

information gained regarding potential consequences and adverse impacts.

- **Transfer levels used in near term planning horizon System models** – Include wording (perhaps in R2.1.4 – Expected transfers and R2.4.3 – Expected transfers) which explains that expected transfers used in the sensitivity cases must not exceed Transfer Capabilities assessment results that were determined in accordance with the effective NERC FAC-013 Reliability Standard.
- **Table 1, Footnote 1** – Revise the wording of footnote 1 of Table to add more clarity. For example, that an element is removed, not just open ended, by a Protection System operation designed to isolate the event fault. The voltage level of an unloaded winding of a three-winding transformer is excluded from the determination.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

Due to the length of time (several years) it took the NERC SDT to develop the final draft, gain industry acceptance and receive FERC approval of the NERC TPL-001-4 standard, we believe that a more comprehensive review is essential at this time to address the ambiguities and enhance clarity in the standard. Therefore, we strongly suggest that the SAR's scope not be limited to just the single point of failure concern resulting from FERC Order No. 754, but be expanded to address all significant issues & concerns identified based on the standard's implementation experience by applicable entities in the industry.

Some of the numerous TPL-001-4 issues & concerns based on Xcel Energy's diverse planning experience in three Regions (MRO, SPP, WECC) are noted below. Additionally, we also support the issues identified by MRO NSRF, which are included as part of our comments under Q.2.

1. Requirement 1 references two standards, MOD-010 and MOD-012, that are slated to retire on July 1, 2016.
2. Requirement 2 requires independent Planning Assessments by both the Planning Coordinator/Authority (PC/PA) and Transmission Planner (TP), yet Requirement 7 states that the PC/PA in conjunction with the TP shall identify each entity's responsibility in completing what may be a single Planning Assessment. We believe that these two Requirements can be consolidated into one better defined Requirement.
3. Both sub-requirements 2.3 and 2.8 address the short circuit analysis required in the Planning Assessment. These are closely interrelated and can be consolidated into one Requirement.
4. Requirement 8 states that TPs shall distribute the Planning Assessment results to adjacent TPs and PCs. In discussion with other TPs, they are not necessarily interested in receiving Planning Assessments from other TPs, but do believe that if a reliability need arises, these should be made available upon request.

Since project 2015-10 will make substantial modifications to the TPL-001-4 standard, we respectfully ask NERC to take this opportunity to include a comprehensive review of the standard within the SAR's scope andhelp address the issues & concerns faced by many in the industry.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer: Yes

Answer Comment:

While we generally support the scope and direction proposed in the SAR, some of the proposed changes to TPL-001-4 described in the SAR (and in this Comment Form) are unclear. Hence, we reserve our judgment on the final scope and the specific changes that will be made to the TPL-001-4 standard. For example, the replacement of FN 13 with the proposed wording but there is no mention of the placement of the functions or types of relay that will be replaced. Further, the meaning of "evaluation of the three-phase faults the described component failures of a Protection System" in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Given the primary goal of this SAR is to appoint a SDT to address recommendations for modifying the NERC Reliability Standard TPL-001-4 it is expected that the SDT would address FERC issues for single points of failure.

However, the SAR contains specific changes from the SPCS report that were recommendations from that team. There were other alternatives identified in the report that should be vetted by a broader audience.

Document Name:

Likes: 0

Dislikes: 0

Richard Vine - California ISO - 2 -

Selected Answer: Yes

Answer Comment:

The ISO suggests that the revised standard should also address whether or not protection systems should require diversely-routed communication paths.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: No

Answer Comment:

Under SAR Information (Industry Need) - ATC has the following recommendations for the SAR SDT to consider:

(1) Please drop the "Modify TPL-001-4 (Part 4.5)" item from the SAR. The existing Part 4.5 text already includes the obligation to consider all (i.e. item number 1 and item number 2) of the stability extreme event items in Table 1. There is no need to add more text to make duplicative reference to item number 2.

(2) **Under SAR Information (page 2) - In addition to the SCPS and SAMS recommendations, ATC recommends the SAR SDT also consider adding other items to the scope of the SAR to address several specific deficiencies that have been found in the TPL-001-4 standard.**

· **Table 1, Header note i** – Please revise note i because the present text can be interpreted to contradict the NERC Definition for Non-Consequential Load Loss. The response of voltage sensitive load and load disconnected from the System by end-user equipment are not Non-Consequential Load Loss. So by definition, response of voltage sensitive load and load disconnected from the System by end-user equipment are excluded from the steady state Non-Consequential Load Loss Allowed performance requirement. Wording like, ". . . associated with a planning event is allowed" may be clearer and not contradictory.

· **Cascading clarification** – Please clarify the understanding the NERC definition of Cascading (e.g. Table 1, header note a). The subsequent loss of system elements, load, or generation is classified as Cascading when it results in widespread electric service interruption. Therefore, the loss of line circuits, transformer circuits, generators, or limited amounts of load due to cascading does not qualify as exceeding the Cascading performance requirement.

· **Load loss due to cascading** – Please address the treatment of load loss due to cascading - perhaps with an additional Table 1 footnote. Load loss due to cascading does not meet the NERC definition of either Consequential Load Loss or Non-Consequential Load Loss. So, cascading load loss does not apply to the Non-Consequential Load Loss Allowed performance requirement. However, an additional performance requirement should probably be added that the sum of cascading load loss and Non-Consequential Load Loss should not exceed an entity's IROL criteria.

· **Use of sensitivity cases in extreme event analysis** – Please revise the wording in R3 and R4 (e.g. referring to Part 2.1 or Part 2.4 without limiting the obligation to planning event studies) to remove the obligation to use sensitivity cases in extreme event studies (i.e. R3.2 and R4.2). Extreme event studies using baseline cases (R2.1.1, R2.1.2, R2.2.1, R2.4.1, and R2.4.2) are essentially probing studies that consider extraordinary contingencies. Extreme event studies using sensitivity cases (R2.1.4 and R2.4.3) are essentially probing studies that consider the compounded effect of both extraordinary contingencies and extraordinary system conditions. The obligation to perform these compound effect studies results in an unreasonable expenditure of resources compared to the information gained regarding potential consequences and adverse impacts.

· **Transfer levels used in near term planning horizon System models** – Please include wording (perhaps in R2.1.4 – Expected transfers and R2.4.3 – Expected transfers) which explains that expected transfers used in the sensitivity cases must not exceed Transfer Capabilities assessment results that were determined in accordance with the effective NERC FAC-013 Reliability Standard.

· **Table 1, Footnote 1** – Please revise the wording of footnote 1 of Table to add more clarity. For example, that an element is removed, not just open ended, by a Protection System operation designed to isolate the event fault. The voltage level of an unloaded winding of a three-winding transformer is excluded from the determination.

Document Name:

Likes: 0

Dislikes: 0

William Temple - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer: Yes

Answer Comment:

While PJM generally supports the scope and direction in the proposed SAR, some of the proposed changes to TPL-001-4 presented in the SAR (and in the Comment Form) are unclear. Therefore, we reserve our judgment on the final scope and the specific changes that will be made to the TPL-001-4 standard. For example, the replacement of Footnote 13 with the proposed wording seems fine, but there is no mention of the placement of the functions or types of relay that will be replaced. Further, the meaning of "evaluation of the three-phase faults the described component failures of a Protection System" in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter	Segment
Brent Ingebrigtson	1,3,5,6
Entity	**Region(s)**
PPL NERC Registered Affiliates	SERC,RFC

Selected Answer: No

Answer Comment:

These comments are submitted on behalf of the following PPL NERC Registered Affiliates ("PPL"): Louisville Gas and Electric Company, Kentucky Utilities Company and PPL Electric Utilities Corporation. The PPL NERC Registered Affiliates are registered in two regions (RF and SERC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

PPL NERC Registered Affiliates believe that this SAR usurps the SDT's role by providing specific language for inclusion in a first draft of TPL-001-5. This is atypical for a SAR form and necessitates comments on a standard even before the standard's first draft. Additionally, the SAR does not include a reliability justification for the revision in the "Detailed Description" section and instead incorporates the SPCS/SAMS report (Order No. 754…) in its entirety. PPL NERC Registered Affiliates believe that, at a minimum, a SAR should include a summary of the justification for any revisions with the SAR form itself.

PPL NERC Registered Affiliates suggest that the SDT consider adding the following language to the standard if the proposed change is added to TPL-001 for Project 2015-10 Single Points of Failure, November 2015.

“For 36 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 36 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, a correction action plan will not be required for a P5 event where an induction motor load stability model results in a transient stability criteria violation.“

The existing standard addresses similar statements:

Requirement 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 Standard TPL-001-4 — Transmission System Planning Performance Requirements 5 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.”

Page 1 third paragraph in section 5. “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:

· P5 (above 300 kV)”

While this language allows some time to build projects, dropping load as written in the above language will not alleviate a transient voltage stability violation as a result of P5 event when combined with the behavior of induction motor loads under requirement 2.4.1. In most cases, the only corrective action plan available is building a redundant protection system which requires appropriate lead times.

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer: Yes

Answer Comment:

While we generally support the scope and direction proposed in the SAR, some of the proposed changes to TPL-001-4 presented in the SAR (and in this Comment Form) are unclear. The final scope and the specific changes that will be made to the TPL-001-4 standard should address the protection components (e.g. batteries, instrument transformers, relays, communications) to be evaluated and how the components will be evaluated. In the second bullet, the replacement of Footnote 13 is fine but the wording should further reflect how the components will be evaluated. Further, the meaning of "evaluation of the three-phase faults the described component failures of a Protection System" in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.

Document Name:

Likes:	0
Dislikes:	0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Liam Stringham	Sunflower Electric Power Corporation	SPP	1
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
John Allen	City Utilities of Springfield	SPP	1,4
Robert Gray	Board of Public Utilities of Kansas City, KS	SPP	3
Mike Kidwell	Empire District Electric	SPP	1,3,5
Kevin Foflygen	City Utilities of Springfield	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer: Yes

Answer Comment:

Yes, we agree with scope and objective of this project. Additionally, we support the fact that the drafting team will be using the recommendations provided in the SPCS and SAMS report to develop a solid foundation for this project. Also, it's pertinent to consider the issues addressing Paragraph 81 as well as retirement in the Standards Development Process. As the project develops, we understand that the SDT scope may change but, we would suggest to the drafting team to work closely with the industry and use their comments and feedback as a corner stone to developing an effective and reliable standard.

Document Name:

Likes:	0
Dislikes:	0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: No

Answer Comment:

Bonneville Power Administration does not agree with the proposal because the proposal does not add significant value. Relay failure represents any protection system failure and should be modeled if not redundant. Bonneville Power Administration proposes to make efforts toward removing R1.1.2 (including known outages with a duration of six months) which would be more appropriate in the operations time frame than in a planning standard. Similarly, removing R2.1.1 (system peak load for either year one or year two….) would be a
more appropriate proposal since it also is more appropriate in the operations time frame rather than a planning standard.

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Dominion

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	Segment
Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer: Yes

Answer Comment:

While we generally support the scope and direction proposed in the SAR, some of the proposed changes to TPL-001-4 described in the SAR (and in this Comment Form) are unclear. Hence, we reserve our judgment on the final scope and the specific changes that will be made to the TPL-001-4 standard. For example, the replacement of FN 13 with the proposed language fails to mention of the placement of the functions or types of relay that will be replaced. We believe it should be more specific.

The meaning of the phrase “evaluation of the three-phase faults the described component failures of a Protection System” in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Matthew Caves	Western Farmers Electric Cooperative	SPP	1,5
Matthew Caves	Western Farmers Electric Cooperative	SPP	1,5
Liam Stringham	Sunflower Electric Power Corporation	SPP	1

Voter Information

Voter

Colleen Campbell

Segment

6

Entity

ACES Power Marketing

Region(s)

NA - Not Applicable

Selected Answer: No

Answer Comment:

(1) We generally agree with the scope and intent of this project, as recommended by the SPCS and SAMS. However, the SAR should clarify the meaning of “protective relays that respond to electrical quantities.” We believe this could include other relays outside the scope of the existing standard, such as sync-check relays. The list of relays that are in scope for this standard should remain at those that clear three-phase faults or other events of operational concerns.

(2) We have similar concerns that the applicability of this standard is inclusive of all BES Elements, not the sub-set identified and analyzed as part of the Section 1600 Data Request. The findings identify that buses under 300 kV are less likely to result in an adverse impact to reliability of the Bulk Power System based from a Protection System single point of failure. Proposing to collect data for all BES Elements poses an unnecessary administrative burden on registered entities and their models, especially considering that the findings do not support additional analysis under 300 kV. Moreover, analysis results identifying issues which adversely impact the reliability of the Bulk Power System could be masked by insignificant concerns.

(3) We recommend developing a methodology for the applicability of this standard that is similar to the criteria used in the Data Request, mainly to those buses more likely to have a significant stability impact on the Bulk Power System.

Document Name:

Likes: 0

Dislikes: 0

Robert A. Schaffeld - Southern Company - Southern Company Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

R. Scott Moore - Southern Company - Alabama Power Company - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John J. Ciza - Southern Company - Southern Company Generation and Energy Marketing - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	**Region(s)**
Associated Electric Cooperative, Inc.	

Selected Answer: No

Answer Comment:

1. In the Order 754 data request, only a select set of busses meeting certain criteria were to be tested. However, the recomended language in the SAR would require entities to provide additional information relating to single points of failure for all BES busses. AECI would request that the additional information required by footnote 13 be only applicable to a select set of BES busses, and that this brightline be determined by the SDT.
2. AECI is not in disagreement with the final recommendation made by the SPCS and SAMS, however we would suggest that the drafting team be able to discuss which course of action would be best. This would allow for wider industry involvement in the decision on how the study of single points of failure should be addressed.

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

ERCOT supports the comments submitted by the Standards Review Committee of the IRC. Comments are below.

While we generally support the scope and direction proposed in the SAR, some of the proposed changes to TPL-001-4 presented in the SAR (and in this Comment Form) are unclear. The final scope and the specific changes that will be made to the TPL-001-4 standard should address the protection components (e.g. batteries, instrument transformers, relays, communications) to be evaluated and how the components will be evaluated. In the second bullet, the replacement of Footnote 13 is fine but the wording should further reflect how the components will be evaluated. Further, the meaning of "evaluation of the three-phase faults the described component failures of a Protection System" in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here.

Kevin Conway - INTELLIBIND - 5 - NA - Not Applicable

Selected Answer:

Answer Comment:

None

Document Name:

Likes: 0

Dislikes: 0

Guy V. Zito - Northeast Power Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

na

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Oncor Electric Delivery - 2 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE noticed the proposed language for Footnote 13 in TPL-001-4, does not match the NERC Glossary term of Protection System.

The language proposed in the SAR for “protective relays” and “DC control circuitry” largely tracks the definition of “Protection System” set forth in the NERC Glossary of Terms. The sole substantive distinction appears to be limiting the general category of “control circuitry” explicitly to “DC control circuitry” consistent with recommendation in the Order No. 754 Report.

In contrast, the SAR (and the Order No. 754 Report) places additional, qualifying language on the definition of "station DC supply" that is not contained in the definition of Protection System in the NERC Glossary of Terms. Specifically, the "Protection System" definition in the NERC Glossary of Terms includes: "Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply)." The SAR (and the recommended language in Order No. 754 Report) qualifies this language by describing "station DC supply" as "single-station DC supply that is not monitored (i.e., not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)."

Texas RE recommends that the SDT use of the existing definition of station DC Supply in the NERC Glossary of Terms. Using consistent language in both Standards would help entities classify their dc supply components in a uniform manner across their compliance program.

Is the intent to create a new definition of station DC supply? If so, Texas RE recommends the SDT request comments from stakeholders regarding a new definition of station DC supply so the rationale for such change can be fully developed.

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

The (future) SDT should emphasize both feasibility and practicality in any future requirements regarding system modeling, and the implementation thereof.

Document Name:

Likes: 0

Dislikes: 0

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - WECC,NPCC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter

John Seelke

Segment

1,3,5,6

Entity

PSEG

Region(s)

WECC,NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Shannon Weaver	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Brad Perrett	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5
Amy Casucelli	Xcel Energy	MRO	1,3,5,6

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: N/A

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Additionally, we also support the issues identified by MRO NSRF as outlined below:

Consider adding other items to the scope of the SAR to address several specific deficiencies that have been found in the TPL-001-4 standard.
• Table 1, Header note i – Revise note i because the present text can be interpreted to contradict the NERC Definition for Non-Consequential Load Loss. The response of voltage sensitive load and load disconnected from the System by end-user equipment are not Non-Consequential Load Loss. So by definition, response of voltage sensitive load and load disconnected from the System by end-user equipment are excluded from the steady state Non-Consequential Load Loss Allowed performance requirement. Wording like, ". . . associated with a planning event is allowed" may be clearer and not contradictory.
• Cascading clarification – Clarify the understanding the NERC definition of Cascading (e.g. Table 1, header note a). The subsequent loss of system elements, load, or generation is classified as Cascading when it results in widespread electric service interruption. Therefore, the loss of line circuits, transformer circuits, generators, or limited amounts of load due to cascading does not qualify as exceeding the Cascading performance requirement.
• Load loss due to cascading – Address the treatment of load loss due to cascading - perhaps with an additional Table 1 footnote. Load loss due to cascading does not meet the NERC definition of either Consequential Load Loss or Non-Consequential Load Loss. So, cascading load loss does not apply to the Non-Consequential Load Loss Allowed performance requirement. However, an additional performance requirement should probably be added that the sum of cascading load loss and Non-Consequential Load Loss should not exceed an entity's IROL criteria.
• Use of sensitivity cases in extreme event analysis – Revise the wording in R3 and R4 (e.g. referring to Part 2.1 or Part 2.4 without limiting the obligation to planning event studies) to remove the obligation to use sensitivity cases in extreme event studies (i.e. R3.2 and R4.2). Extreme event studies using baseline cases (R2.1.1, R2.1.2, R2.2.1, R2.4.1, and R2.4.2) are essentially probing studies that consider extraordinary contingencies. Extreme event studies using sensitivity cases (R2.1.4 and R2.4.3) are essentially probing studies that consider the compounded effect of both extraordinary contingencies and extraordinary system conditions. The obligation to perform these compound effect studies results in an unreasonable expenditure of resources compared to the information gained regarding potential consequences and adverse impacts.
• Transfer levels used in near term planning horizon System models – Include wording (perhaps in R2.1.4 – Expected transfers and R2.4.3 – Expected

transfers) which explains that expected transfers used in the sensitivity cases must not exceed Transfer Capabilities assessment results that were determined in accordance with the effective NERC FAC-013 Reliability Standard.
• Table 1, Footnote 1 – Revise the wording of footnote 1 of Table to add more clarity. For example, that an element is removed, not just open ended, by a Protection System operation designed to isolate the event fault. The voltage level of an unloaded winding of a three-winding transformer is excluded from the determination.

Document Name:

Likes: 0

Dislikes: 0

Leonard Kula - Independent Electricity System Operator - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment:

The proposed changes to R4.5 appear to add unnecessary redundancy and eliminate the efficiencies gained through applicable "engineering judgment." This issue should be addressed, as noted in our response to question #1, by including proper industry vetting that considers input from a broader audience.

Document Name:

Likes: 0

Dislikes:	0

Richard Vine - California ISO - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

William Temple - PJM Interconnection, L.L.C. - 2 - SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brent Ingebrigtson - PPL NERC Registered Affiliates - 1,3,5,6 - SERC,RFC

Group Information

Group Name: PPL NERC Registered Affiliates

Group Member Name	Entity	Region	Segments
Brent Ingebrigtson	LG&E and KU Energy, LLC	SERC	1,3,5,6
Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
Charlie Freibert	LG&E and KU Energy, LLC	SERC	3
Dan Wilson	LG&E and KU Energy, LLC	SERC	5
Linn Oelker	LG&E and KU Energy, LLC	SERC	6
Justin Bencomo	LG&E and KU Energy, LLC	SERC	1,3,5,6

Voter Information

Voter
Brent Ingebrigtson

Segment
1,3,5,6

Entity
PPL NERC Registered Affiliates

Region(s)
SERC,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Liam Stringham	Sunflower Electric Power Corporation	SPP	1
Jim Nail	City of Independence, Power & Light Department	SPP	3,5
Mahmood Safi	Omaha Public Power District	MRO	1,3,5
John Allen	City Utilities of Springfield	SPP	1,4
Robert Gray	Board of Public Utilities of Kansas City, KS	SPP	3
Mike Kidwell	Empire District Electric	SPP	1,3,5
Kevin Foflygen	City Utilities of Springfield	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We have a concern in reference to the recommendations suggested in the SAR on page 2….bullet number 3. We would ask the drafting team to provide clarity on what is being suggested by this particular recommendation. In our discussion, we interpreted that the recommendation is suggesting that entities will have to obtain substantially more data than what is already required. This could cause issues in getting the study(s) completed in a proper time frame. However if that is the case, we would suggest to the drafting team to use some form of criteria limiting the study of component failures to only High Priority Facilities (for example 200kV

	and above and sub-200kV IROL facilities as in FAC-003) instead of all of the BES Elements in order to reduce the magnitude of study and data collection.
Document Name:	
Likes:	0
Dislikes:	0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Allie Gavin - International Transmission Company Holdings Corporation - 1 - MRO,SPP,RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7 - NPCC

Group Information

Group Name: RSC no Con Edison, Dominion

Group Member Name	Entity	Region	Segments
Paul Malozewski	Hydro One.	NPCC	1
Guy Zito	Northeast Power Coordinating Council	NPCC	NA - Not Applicable
Brian Shanahan	National Grid	NPCC	1
Rob Vance	New Brunswick Power	NPCC	1
Robert J. Pellegrini	United Illuminating	NPCC	1
Sylvain Clermont	Hydro Quebec	NPCC	1
Edward Bedder	Orange and Rockland Utilities	NPCC	1
Mark J. Kenny	Eversource Energy	NPCC	1
Gregory A. Campoli	NY-ISO	NPCC	2
Si Truc Phan	Hydro Quebec	NPCC	2
Randy MacDonald	New Brunswick Power	NPCC	2
David Burke	Orange and Rockland Utilities	NPCC	3
Wayne Sipperly	New York Power Authority	NPCC	4
David Ramkalawan	Ontario Power Generation	NPCC	4
Glen Smith	Entergy Services	NPCC	4
Brian O'Boyle	Con Edison	NPCC	5
Brian Robinson	Utility Services	NPCC	5
Bruce Metruck	New York Power Authority	NPCC	6
Alan Adamson	New York State Reliability Council	NPCC	7
Kathleen M. Goodman	ISO-New England	NPCC	2
Helen Lainis	Independent Electricity System Operator	NPCC	2
Michael Jones	National Grid	NPCC	3
Silvia Parada Mitchell	NextEra Energy	NPCC	4

Voter Information

Voter	**Segment**
Ruida Shu	1,2,3,4,5,6,7
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

When a standard is being revised, all open issues related to that standard should be resolved. In the interest of efficiency we recommend that the two directives from FERC Order 786 be added to the scope of this SAR. For reference please see the Reliability Standards Development Plan 2016 Projects 2015-10: "From FERC Order 786:

1. Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.
2. 2. Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."

The SAR should address all directives and all changes needed in the standard.

Additional points needing clarifications which should be added to the scope of the SAR and provide needed corrections to TPL-004-1 include:

1. The SAR requires studying three phase faults with protection system failure. It is not clear how the protection systems deficiencies will be corrected, when identified, since there is no obligation to the meet performance criteria for extreme events.

2. The revised standard should formalize the process described in the Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request that was used to identify the protection systems that do not

meet the redundancy criteria. The protection systems owners will need to have obligations since they are responsible for both identifying and correcting the design deficiencies.

3. There are situations when non BES elements are connected to BES buses (e.g. radial circuits supplying loads). The SAR needs to clarify which protection systems are subject to the standard since an un-cleared close in fault on a non BES element connected to a BES bus has the same reliability consequence as an un-cleared close in fault on a BES element. Do the protection systems installed on non BES elements but connected to BES buses need to meet redundancy criteria?

4. Since the TPL-001-4 standard is going to be revised we believe there is a good opportunity to clarify the following discrepancy:

In Table 1 of the standard, the use of non-consequential load loss is allowed under Footnote 12 conditions for P1, P2, and P3 planning events for the elements operated at EHV level. However, planning events P4 and P5 do not allow the use of non-consequential load loss at EHV level.

Document Name:

Likes: 0

Dislikes: 0

Colleen Campbell - ACES Power Marketing - 6 - NA - Not Applicable

Group Information

Group Name: ACES Standards Collaborators

Group Member Name	Entity	Region	Segments
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
John Shaver	Southwest Transmission Cooperative, Inc.	WECC	1
Shari Heino	Brazos Electric Power Cooperative, Inc.	TRE	1,5
Michael Brytowski	Great River Energy	MRO	1,3,5,6
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5
Scott Brame	North Carolina Electric Membership Corporation	SERC	3,4,5
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
Matthew Caves	Western Farmers Electric Cooperative	SPP	1,5
Matthew Caves	Western Farmers Electric Cooperative	SPP	1,5
Liam Stringham	Sunflower Electric Power Corporation	SPP	1

Voter Information

Voter	Segment
Colleen Campbell	6
Entity	**Region(s)**
ACES Power Marketing	NA - Not Applicable

Selected Answer:

Answer Comment:

(1) We agree with the directions given in the SAR to consider retiring requirements under Paragraph 81 criteria. However, we do have concerns that the SAR does not specify requirements within this standard, such as Requirement R4, parts 4.2 and 4.5, which would qualify for P81 criteria or further consolidation. Moreover, Requirement R1 references reliability standards MOD-010 and MOD-012 which are projected to be retired in 2016. We recommend the SAR be expanded to incorporate requirement consolidations and retirements, both current and projected.

(2) We thank you for this opportunity to provide these comments.

Document Name:

Likes: 0

Dislikes: 0

Robert A. Schaffeld - Southern Company - Southern Company Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

R. Scott Moore - Southern Company - Alabama Power Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John J. Ciza - Southern Company - Southern Company Generation and Energy Marketing - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Group Information

Group Name: AECI

Group Member Name	Entity	Region	Segments
Mark Ramsey	N.W. Electric Power Cooperative, Inc.	SERC	1
John Stickley	N.W. Electric Power Cooperative, Inc.	SERC	3
Kevin White	Northeast Missouri Electric Power Cooperative	SERC	1
Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	SERC	3
Michael B Bax	Central Electric Power Cooperative	SERC	1
Adam M Weber	Central Electric Power Cooperative	SERC	3
Denise Stevens	Sho-Me Power Electric Cooperative	SERC	1
Jeff L Neas	Sho-Me Power Electric Cooperative	SERC	3
Walter Kenyon	KAMO Electric Cooperative	SERC	1
Theodore J Hilmes	KAMO Electric Cooperative	SERC	3
Phillip B Hart	Associated Electric Cooperative Inc.	SERC	1
Todd Bennett	Associated Electric Cooperative Inc.	SERC	3
Matt Pacobit	Associated Electric Cooperative Inc.	SERC	5
Brian Ackermann	Associated Electric Cooperative Inc.	SERC	6

Voter Information

Voter	Segment
Phil Hart	1

Entity	Region(s)
Associated Electric Cooperative, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)		
Date Submitted:	October 05, 2015		
SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standards		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Modifications have been identified to Reliability Standard TPL-001-4 based on the following: Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section

SAR Information

1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.
 	
As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:
 	
• For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  ▪ Replace "relay" with "component of a Protection System," and
  ▪ Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
• For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  ▪ Remove the phrase "or a relay failure[13]" from items a, b, c, and d to create distinct events only for stuck breakers.
  ▪ Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure[13]" with "a component failure of a Protection System[13]."
• Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
• Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

[1] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

SAR Information

Item 2: In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:

- Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments
- Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."

Item 3: Further, references to MOD-010 and MOD 012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards.

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

The ~~primary~~ goal of this SAR is to:

1. Consider the ~~appoint a Standard Drafting Team (SDT) to address~~ recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request";
2. Address the two FERC directives from Order No. 786; and
3. Update the references to the MOD Reliability Standards in TPL-001.

~~.~~"

Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?):

Provide clear, unambiguous requirements and Results-based Reliability Standards that will: (1) reflect condiseration of~~standards to address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;" (ii) address the two FERC directives from Order No. 786 citd above; and (iii) and update the references to the MOD Reliability Standards cited in TPL-001. ~~.~~"

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

The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", address the two FERC directives, update the references to the MOD Standards,~~"~~ and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and

SAR Information
implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard's requirements and measures.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to consider~~address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request." This ~~The SDTs execution of this SAR would, in addition, consider retirements to requirements under Paragraph 81 criteria. The SPCS and SAMS~~ report ~~titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"~~ is incorporated ~~in~~ its entirety into this SAR~~,~~ so as not to unnecessarily repeat or paraphrase the substance of the report. In addition, the SDTs execution of this SAR would consider retirements to requirements under Paragraph 81 criteria.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

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Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2015-10 Single Points of Failure Standards Authorization Request (SAR)**. The electronic form must be submitted by **8 p.m. Eastern, Friday, June 24, 2016.**

Documents and information about this project are available on the Project 2015-10 Single Points of Failure. If you have questions, contact Jordan Mallory via email or by telephone at 404-446-9733.

Background Information

The Standards Authorization Request Drafting Team (SAR DT) for Project 2015-10 Single Points of Failure (TPL-001) made changes to the first posting of the SAR based on comments received from industry. The changes include:

1) Replacing the word "address" with "consider" regarding the recommendations of the SCPS and SAMS report titled Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request.
2) Addressing the two (2) outstanding FERC directives from FERC Order No. 786:
   a. Reliability Standard TPL-001-4 requires an entity to consider planned maintenance outages greater than six months in duration in its studies. Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.
   b. The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.
3) Updating the MOD references in Requirement R1, Measure M1 and the Violation Severity Levels sections of the TPL-001 standard to reflect the retirement of MOD-010 and MOD-012 effective July 1, 2016.

Other comments received from the November 12 through December 17, 2015 SAR comment period were reviewed. As the issues raised in these comments were determined to not present reliability risks, they were not considered in scope for this project. However, these comments may be considered during the next Enhanced Periodic Review of TPL-001.

Question

1. Do you agree with the proposed changes to the SAR? If no, please provide comments.

☐ Yes
☐ No

Comments:

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Standards Announcement

Project 2015-10 Single Points of Failure
Standards Authorization Request

Informal Comment Period Open through June 24, 2016

Now Available

An informal comment period for the **Project 2015-10 Single Points of Failure** Standards Authorization Request (SAR), is open through **8 p.m. Eastern, Friday, June 24, 2016**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 8 p.m. Eastern).

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at (404) 446-9733.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2015-10 Single Points of Failure SAR
Comment Period Start Date:	5/26/2016
Comment Period End Date:	6/24/2016
Associated Ballots:	

There were 31 sets of responses, including comments from approximately 31 different people from approximately 31 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed changes to the SAR? If no, please provide comments.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
ACES Power Marketing	Colleen Campbell	6	NA - Not Applicable	ACES Standards Collaborators	Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Chip Koloini	Golden Spread Electric Cooperative, Inc.	5	SPP RE
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	RF
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
SERC Reliability Corporation	David Greene	10	SERC	SERC PSS	Shih-Min Hsu	Southern Company Services – Transmission	1	SERC
					John Sullivan	Ameren	1	SERC
					Phil Kleckley	SCE&G	1	SERC
					David Greene	SERC	10	SERC
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF

					Matt Goldberg	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
MRO	Emily Rousseau	1,2,3,4,5,6	MRO	MRO-NERC Standards Review Forum (NSRF)	Joe Depoorter	Madison Gas & Electric	3,4,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,3,5	MRO
					Dave Rudolph	Basin Electric Power Cooperative	1,3,5,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Jodi Jenson	Western Area Power Administration	1,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Mahmood Safi	Omaha Public Utility District	1,3,5,6	MRO
					Shannon Weaver	Midwest ISO Inc.	2	MRO
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Brad Perrett	Minnesota Power	1,5	MRO
					Scott Nickels	Rochester Public Utilities	4	MRO
					Terry Harbour	MidAmerican Energy Company	1,3,5,6	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,4,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

				Seattle City Light Ballot Body	Dana Wheelock	Seattle City Light	3	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,3,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7	NPCC	RSC no ISO-NE, IESO	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Rob Vance	New Brunswick Power	1	NPCC
					Mark J. Kenny	Eversource Energy	1	NPCC
					Gregory A. Campoli	NY-ISO	2	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC

					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Brian Shanahan	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con-Edison	1	NPCC
					Kelly Silver	Con-Edison	3	NPCC
					Peter Yost	Con-Edison	4	NPCC
					Sean Bodkin	Dominion	4	NPCC
					Silvia Parada Mitchell	NextEra Energy	4	NPCC
					Brian O'Boyle	Con-Edison	5	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jason Smith	Southwest Power Pool Inc	2	SPP RE
					Kim VanBrimer	Southwest Power Pool Inc	2	SPP RE
					Derek Brown	Westar Energy	1,3,5,6	SPP RE
					Charles Hendrix	Southwest Power Pool Inc	2	SPP RE

					john Allen	City Utilities of Springfield	1,4	SPP RE
					jonathan Hayes	Southwest Power Pool Inc	2	SPP RE
					Don Hargrove	Oklahoma Gas and Electric Co.	1,3,5,6	SPP RE
					Jim Nail	Independence Power and light	3,5	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Robert Gray	Board of Public Utilities (BPU)	NA - Not Applicable	NA - Not Applicable
					TARA Lightner	Sunflower	1	SPP RE

1. Do you agree with the proposed changes to the SAR? If no, please provide comments.

Michelle Amarantos - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS believes this creates little risk in the planning horizon. Any potential issues are best identified through next-day, real time and seasonal analysis studies (in conjunction with applicable RCs) to addresses these short duration issues, rather than through TPL-001-4. These planned maintenance outages tend to be rescheduled, as needed, in the operations horizon to account for present conditions. Including these shorter duration planned outages in the Planning Horizon would create the need for duplicative staff, duplicative equipment, additional computing time, and compliance enforcement costs related to performing additional annual planning assessments for TPL-001- 4 which are already adequately and properly covered in studies performed in the operations horizon.

Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

As explained in detail below, Xcel Energy agrees with addressing item 1 (single points of failure) and item 3 (update the reference to MOD standards in R1) with the scope of the SAT, but disagree with item 2 (FERC directives) included in its entirety within the scope. The following comments are in reference to the items listed in the Industry Need and Purpose/Goals sections of the SAR.

Item 1: Agree with replacing "address" by "consider" in the Purpose/Goals section, but find that corresponding changes in the Industry Need section are missing. Specifically, the lead-in sentence in the Industry Need section, "*Modifications have been identified to TPL-001-4*..." implies that the SAMS/SPCS recommendations for modifying TPL-001-4 described within Item 1 are the specific changes to be implemented in TPL-001-4 . It appears that recommendations will be addressed instead of being considered.

Item 2: Agree that SAR scope may include addressing the FERC directives from Order 786. However, the scope should be limited to included "true" FERC directives, which we contend is only contained in Paragraph 40 and not in Paragraph 89. We observe the following clear distinction in the language used by FERC in Paragraph 40 versus Paragraph 89. While Paragraph 40 is certainly a directive ("directs NERC to modify Reliability Standard TPL-001-4") to address the identified (BES reliability) concern and have has the expectation that the concern would be addressed at the earliest opportunity to modify TPL-001-4, we note that Paragraph 89 does not convey a FERC directive to address the stated issue. In fact, Paragraph 89 unambiguously states "*the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.*" Consequently, we disagree with including Paragraph 89 within the scope of the SAR. In fact, if addressing Paragraph 89 is not deferred to the next review cycle of TPL-001-4, we see this as contradictory and inconsistent with the SAR-DT's position to defer addressing the TPL-001-4 issues and ambiguities (as identified by Xcel Energy and several other entities in comments submitted for the previous SAR posting) until the next regular review cycle of TPL-001-4. Due to the reasons cited above, we strongly recommend that addressing Paragraph 89 be excluded from the scope of this project.

Item 3: Agree with revising R1 to update reference to soon to be outdated MOD standards.

Additional editorial changes recommended below:

Industry Need Section: Another reason the lead in sentence in the Industry Need section must be revised is that addressing the Paragraph 40 directive comprehensively may require making modifications to additional standards besides TPL-001-4. For instance, modifications may be needed to the IRO-017-1, Outage Coordination, standard whose purpose and applicability has significant overlap with the reliability concern noted in Paragraph 40.

Identify the Objectives Section: Please ensure that a consistent numbering format is used for all three items. Also, please fix the spelling error typos (condiseration, citd, etc)

Detailed Description Section: Shouldn't all three items be described in this section as well? It appears that only Item 1 is described. Although it is stated that the SPCS/SAMS report "is incorporated in entirety into this SAR" we do not find it appended in the posted SAR.

Likes 0	
Dislikes 0	
Response	
David Jendras - 1,3,6	
Answer	No
Document Name	
Comment	

Regarding Item 1: We disagree with changing the word “address” to “consider” in regards to the SPCS/SAMS recommendations. We believe the scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word “consider” will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. In our opinion such changes would open the standard to many interpretations, creating significant additional study effort without clear performance-based requirements, which would also lead to future compliance issues. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further “consideration” by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. The SAR should also include the specific evaluation process and design criteria which were inlcuded in the FERC Order 754 study work. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

Regarding Item 2a: We are concerned with the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant. The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, we believe all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.

Some additional points to consider:

- The purpose of the standard TPL-001-4 is to “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”. Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.

- Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak.

- During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the operating horizon.

- System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.

Regarding Item 2b: We believe there is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. If there is an outage of long lead time equipment, system operations will operate around any problem that might be indicated by their analysis. From a stability standpoint this would most likely be a small limitation on the amount of generation at a plant near the outaged element.

Regarding Item 3: No problems are foreseen with updating references relevant to the retirement of MOD-010 and MOD-012.

Likes 0	
Dislikes 0	

Response

David Greene - 10, Group Name SERC PSS

Answer	No
Document Name	

Comment

Regarding Item 1: We disagree with changing the word “address” to “consider” in regards to the SPCS/SAMS recommendations. The scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word “consider” will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further “consideration” by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

Regarding Item 2a: With the various categories of contingencies which need to be considered already as part of system assessment work related to compliance with Reliability Standard TPL-001-4, both single and multiple element contingencies, to further give consideration to outages of less than 6 months duration would appear to be needlessly redundant. The six month time frame for including planned outages was intentionally chosen by the TPL Standard Drafting Team to be the correct time frame to make sure that outages which can cover critical peak seasons would be included in the planning analysis. Outages shorter than this are not likely to occur over critical peak seasons. Furthermore, we believe all planned outages are studied by the Operations Planning Department. They will take the necessary steps to operate around an outage. There is no risk to the reliability of the grid if planned outages are not studied (by the Transmission Planner) in planning assessments because the outages are studied by Operations Planning.

Some additional points to consider:

1 The purpose of the standard TPL-001-4 is to “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”. Outages that would be scheduled in the planning horizon would be subject to the performance requirements of this standard. Outages that would be scheduled in the operating horizon should be subject to the performance requirements of other standards.

2 Planned maintenance and construction outages typically last from a few days to a few weeks and occur during off-peak time periods with load levels ranging from light load to shoulder peak.

3 During the construction and maintenance seasons multiple facilities are out of service at the same time and are studied in the operating horizon.

4 System adjustments, including transmission switching and generation redispatch (develop short term operating guides), are made as needed to accommodate planned maintenance and construction outages.

Regarding Item 2b: There is very little risk if stability analysis is not performed for the unavailability of long lead time equipment. If there is an outage of long lead time equipment, system operations will operate around any problem that might be indicated by their analysis. From a stability standpoint this would most likely be a small limitation on the amount of generation at a plant near the outaged element.

Regarding Item 3: No problems are foreseen with updating references relevant to the retirement of MOD-010 and MOD-012.

The comments above are from individial members of the SERC Planning Standards Subcommittee and do not necessarily reflect the positions of SERC or the SERC Board of Directors.

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - 1, Group Name Southern Company	
Answer	No
Document Name	

Comment

We disagree with changing the word “address” to “consider” in regards to the SPCS/SAMS recommendations. The scope of the effort for item 1 should be limited to what was recommended by SPCS/SAMS. The word “consider” will allow the scope to be enlarged beyond the recommendations from the subject matter experts in the industry – SPCS/SAMS. To the extent that the recommendations already identified and documented by SPCS/SAMS represent the best solution(s), further "consideration" by the SDT is not necessary to meet the FERC directives as this would further tie-up industry resources.

Likes 0	
Dislikes 0	

Response

John Pearson - 2 - NPCC

Answer	No
Document Name	

Comment

1. While we agree with the overall purpose and changes to the SAR, applying the single point of failure testing to the entire BES is a significant excess that will likely end up with increased spending and very little reliability benefit. It should only be required to be performed on certain facilities, like those the FERC Order 754 test used. This would limit the testing to facilities with the potential for instability, uncontrolled separation, or cascading outages. We recommend the goal 1 of the SAR be modified to:

"Consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", allowing consequential and non-consequential load loss, but not cascading."

In addition, we note that the recent Cost Effectiveness Pilot results show that industry is virtually unanimous in stating that the effect of not considering outages of less than six months is very low risk and and be considered under IRO-017 Outage Coordination. We recommend that goal 2 of the SAR be modified to:

" Address the reliability objectives of the two FERC directives from Order No. 786, which may be able to be accomplished more cost-effectively by considering which, if any, changes are needed to TPL-001, or possibly other NERC standards, such as IRO-017

Likes 0	
Dislikes 0	

Response

Emily Rousseau - 1,2,3,4,5,6 - MRO, Group Name MRO-NERC Standards Review Forum (NSRF)

Answer	No
Document Name	

Comment

Table 1 footnote 13 Protection System revisions

First, we recommend that the “and open circuit” revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have a single DC supply and no open circuit monitoring. So, the new open circuit criterion may result in the identification system performance deficiencies at many substations. The corrective action of adding open circuit monitoring may not be feasible and have an unreasonable cost. The corrective action of adding a dual DC supply may also have an unreasonable cost. The initial cost of adding a redundant DC supply at a single station might cost over $500,000 if there is room in the existing control house and even more if the control house has to be expanded. In addition, there is the ongoing cost of peforming the maintenance and testing required by the NERC PRC-005-6 Relibility Standard.

FERC Order 754 conclusions were based on the criteria of both a significant number of transmission interconnections and a 2000 MW stability impact. So, it is reasonable to expect that the addition of the FERC Oder 754 contingency criteria to the TPL-001 standard should have the same system performance criteria as Order 754.

The reliability benefits of the “and open circuit” revision are may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015. And there is no assertion that the system impacts associated with these protection system misoperations were significant.

Second, we also recommend that the “DC control circuitry” proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. So, the new DC control circuity criterion may result in identification system performance deficiencies at many substations. The corrective action of adding dual DC control circuit may have an unreasonable cost for the same reasons noted above for adding a dual DC supply.

Six month threshold for planned maintenance outages

As part of the six-month threshold, the SDT should consider giving Transmission Planners and Planning Coordinators flexibility to evaluate planned outages of less than six month duration in combination with “no load loss” planning events (e.g. P1, P2.1, P3, and selected EHV contingencies). The contingency event combinations would be those that risk the loss of a significant amount of firm load or firm transmission service interruption during system off peak load conditions when these shorter planned outages would typically be scheduled.

Likes 0	
Dislikes 0	

Response

Terry BIlke - 2

Answer	No
Document Name	

Comment

MISO believes that planned maintenance outages should be considered in planning for the reliable operation of the BPS. If the planning function does not provide for a robust system with sufficient adequacy to allow each facility an opportunity to be removed from service for planned maintenance during periods when maintenance is typically performed (off-peak) and while simultaneously allowing the system to be operated in a manner that is secure for

N-1 contingencies during the planned outage, the RC outage coordination process could be backed into a corner where they are unable to confidently approve certain maintenance outage requests. Given that a core purpose of planning is to ensure the system is adequate, reliable and robust under future conditions, the need for performing future maintenance of facilities cannot be ignored. However, including only scheduled outages with a 6 month duration or longer will not meet the objective of ensuring the system is adequate to accommodate future maintenance, as this method will not verify that the system will support maintenance of each facility where that facility is required to be removed from service. Therefore, the standard should be revised to remove the 6 month planned outage requirement and instead reinstate the provisions in the previous TPL standard where off-peak planning cases are analyzed to ensure the system is capable of supporting a planned outage for each element of the system while simultaneously being secure for the next contingency.

As we mentioned in our cost-effectiveness survey response, if the TPL-001-4 standard were modified simply by a rule change for processing P6 contingencies during off-peak cases (Load shed would not be allowed as a mitigation measure), simulation of a facility being removed for maintenance and the resulting system satisfying the n-1 reliability criteria could be assessed for any time in the Planning Horizon. So removing the 6 month duration requirement in the current standard (which requires a special simulation and cost to complete) and replacing it with the above modification would be effective and require virtually no additional cost.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

Seattle City Light SMEs had the following feedback:

Please clarify what components are included in ‘component of a Protection System’. Does this include backup AC and DC protection systems? Does this include a wire and fuses? If redundant relays are fed from a single DC circuit breaker, is it non-redundant? Or are we only speaking of Lock-Out Relays and Aux Relays? Failure of a lockout or aux relays will be interpreted by the tripping relay as a breaker failure, and the trip will be sent out via a different channel. This is modeled in P4.

For Table 1- Steady State & Stability Performance Extreme Events, under the Stability column, No. 2 – The SAR is requesting that four new events are added replacing “a relay failure” with “a component failure of a Protection System”. Once again, if a relay issues a trip, and the fault is not cleared, the breaker failure scheme will operate. These scenarios are currently being studied. What are we trying to address with these new additions?

Need clarification on what a “single point of failure” means with regards to this standard in the larger scheme.

Why does the the planned outage window need to be reduced as this study is included in operations seasonal assessment studies.

Spare transformer consideration is not needed as this is handled with extreme event analysis.

City Light thanks you for taking our comments into consideration.

Likes 0	

Dislikes 0	
Response	
Jeffrey Watkins - 5 - WECC	
Answer	No
Document Name	
Comment	

NV Energy suggests that the revised standard include all components of a protection system and not just the components presently proposed under footnote 13. NV Energy feels that the Transmission Planner should consider all protection system components in its study area and determine which non-redundant protection system component would affect their planning area the most and study it. By limiting which protection system component to study, there is a potential reliability gap by not studying an excluded protection system component.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

At this time, Duke Energy's main concern is to what degree redundancy will be required in the “Protection System,” and what all would be included in the “components” of the Protection System.

If the authors of the new document intend to base their requirements on the definitions of redundancy in the 2008 NERC technical paper titled “Protection System Reliability Redundancy of Protection System Elements”, a large number of “components” and their current state of implementation would have to be examined/reviewed. This could require a significant volume of work/cost to become compliant based on future document requirements. The following are some questions that would need to be answered::

1. Statement: In current state, many protection and control cables run through a single tray and outdoor trench system.

   Questions/Concerns: To address single component failure, would multiple cable trays or divided cable trays be required? This would potentially be a massive effort to address this issue. A separate secondary trench could be difficult to fit into some entities existing designs.

2. Statement: Many control houses are limited in room and panel space. Many legacy transmission designs have used a single panel for the protection and control of either 1 or 2 transmission lines, or a single panel for 2 bus differential designs. Due to space availability, some entities may use two primary differential systems in one panel and a separate shared secondary in another panel.

   Questions/Concerns: Would future requirements would require the use of 2 panel designs (one for primary and one for secondary protection), and would it be required to have such panels physically separated? In conjunction with separate cabling routing requirements, would the panels have to be lined up on separate rows feeding the separate systems? In order to address this type of a requirement, a significant number of control house additions/replacements would be required.

3. Statement: Many legacy designs use a single DC Panel as well as a single DC source to both primary and secondary protection. While newer designs have used 2 DC sources to the protection (one for primary and one for secondary), many existing substations continue to use one DC panel.

Questions/Concerns: It appears that single DC Panel designs would no longer be acceptable, and all of the legacy DC designs that use a single DC sources in conjunction with fuses to separate DCs for primary and secondary protection would no longer meet a “component” redundancy requirement. This could potentially be a huge undertaking to address existing infrastructure should this become a requirement.

4. Statement: There does not appear to be a clear understanding of when redundant batteries would be required OR what would be an acceptable way to monitor substation battery health.

Questions/Concerns: Would the battery monitoring system need to monitor all cells of the battery? In many cases the health of a battery cannot be determined unless the charger is removed and DC load is placed on the battery; would this be a requirement of the monitoring system?

Until acceptable battery monitoring systems are defined, the scope and magnitude of this requirement cannot be determined.

5. Statement: Pilot communications are a “component” of the protection system. It is unclear what is acceptable and what defines a single component of pilot protection communications.

Questions/Concerns: Are two independent fiber optics run through a single static wire considered separate components, or by being in a single static wire are they considered a single point of failure?

If communication multiplexers are used in the pilot protection, would 2 complete separate communication multiplexer boxes be required to meet the redundancy requirement? Would one multiplexer with 2 independent power supplies be acceptable to meet single component failure requirements? Would one multiplexer with using multiple cards for communication be considered redundant?

6. Statement: Carrier equipment is used in many Directional Comparison Blocking (DCB) protective schemes in transmission. Some entities continue the use of carrier equipment as a reliable means of pilot protection, especially where no other pilot communications are available.

Questions/Concerns: What degree of redundancy would be required on systems using power-line carrier? Would multiple frequency tuners and traps be considered n-2 component failures? If installing multiple sets of tuners and traps to achieve full redundancy becomes required, this could be physically difficult to perform, as well as being financially burdensome.

7. Statement: For the carrier schemes, some entities use frequency shift DCUB, POTT, & BFTT which use up additional frequency band requirements. In the case of BFTT (remote breaker failure trip), some only use one carrier channel for both line schemes.

Question: Should the BFTT channel also be redundant in all cases? Should the local and remote Lockout relays also be separated into redundant schemes?

8. Statement: Many breakers and transformers in service have a limited number of CTs available for protection. In many cases the primary and secondary protection share CTs. Sometimes it is physically impossible to add additional CTs to existing breakers and transformers.

Questions/Concerns: If CT failure is evaluated in these protection systems, it would require the replacement of these breakers and transformers. This would have significant financial impacts, and could take many years to address. Are these types of concerns being addressed by the standard drafting team?

Can different adjacent primary differential schemes share the same CT?

9. Statement: Some entities have existing breakers that use a single trip coil.

Questions/Concerns: Would all of the older breakers with one trip coil require replacement? If an older breaker with one trip coil is replaced with a 2 trip coil breaker, would this mandate a complete protection upgrade that would require the use of both trip coils? Is this correct (it would not appear acceptable to operate a single trip coil design with a 2 trip coils available in a newer breaker)?

10. Statement: Many free standing CTs have multiple cores, and many potential transformers have multiple secondary outputs. Catastrophic failure of a single free standing CT could result in the simultaneous loss of many currents to the protective system. While some of the newer protection installations use two potential transformer outputs independently (one voltage to primary and one to secondary), many do not.

Questions/Concerns: If these types of CTs and Potential Transformers are viewed as a "component" of the protective system and a source of multiple simultaneous impacts to both primary and secondary protective systems, significant upgrades and instrument transformer installations would be required to address risks associated with component failure. This could be an overwhelming task to address these type of component failures.

11. Statement: IT requirements and their redundancy requirements on communications are not clear at this time. Questions/Concerns: Some requirements state that monitoring could alleviate the need for redundancy of a component (example- batteries); what redundancy is required in the monitoring component? Do these types of systems require redundancy in power supply and communications?

Likes 0	
Dislikes 0	

Response

Maryclaire Yatsko - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Seminole's comments regarding the proposed SAR, its goal(s), and the newly appointed Standard Drafting Team, includes several items for the team's consideration as they review the existing TPL-001-4 standard in light of Order 754 and single points of failure:

1. Order 754, for most entities, resulted in voluminous amounts of coordination and study work for planning and system protection engineers in evaluating single points of failure, even with a limited scope of including only those facilities that met the criteria of Table 1.1 "Buses to be tested." Seminole requests the drafting team strongly consider the impact of changing the word "relay" with "component of protection system" in light of the Order 754 effort, understanding that a Planning Assessment is required under R1 of TPL-001-4 to be completed annually which may equate to entities having to double up on planning staff to fulfill this increased TPL scope due to what appears to be a harmless word change.

2. If a change is made as a result of the drafting team review, Seminole requests that the drafting team give strong consideration of including a criteria for which buses need to be evaluated as part of the "annual Planning Assessment" for single points of failure, similar to the criteria used in Order 754 rather than using subjective terminology such as "that create the most severe impact."

Seminole requests the following additional item as part of the drafting team scope:

Evaluate R1 of TPL-001-4 to determine what portions of R1 can be removed/retired in light of the newly enforceable MOD-032 standard.

Likes 0	
Dislikes 0	

Response

larry brusseau - 1	
Answer	No
Document Name	
Comment	

- Table 1 footnote 13 Protection System revisions

First, I recommend that the “and open circuit” revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contingencies be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have a single DC supply and no open circuit monitoring. So, the new open circuit criterion may result in the identification system performance deficiencies at many substations. The corrective action of adding open circuit monitoring may not be feasible and have an unreasonable cost. The corrective action of adding a dual DC supply may also have an unreasonable cost. The initial cost of adding a redundant DC supply at a single station might cost over $500,000 if there is room in the existing control house and even more if the control house has to be expanded. In addition, there is the ongoing cost of performing the maintenance and testing required by the NERC PRC-005-6 Reliability Standard.

FERC Order 754 conclusions were based on the criteria of both a significant number of transmission interconnections and a 2000 MW stability impact. So, it is reasonable to expect that the addition of the FERC Oder 754 contingency criteria to the TPL-001 standard should have the same system performance criteria as Order 754.

The reliability benefits of the “and open circuit” revision are may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015. And there is no assertion that the system impacts associated with these protection system misoperations were significant.

Second, I also recommend that the “DC control circuitry” proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contingencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. So, the new DC control circuity criterion may result in identification system performance deficiencies at many substations. The corrective action of adding dual DC control circuit may have an unreasonable cost for the same reasons noted above for adding a dual DC supply.

- Six month threshold for planned maintenance outages

I have some concerns in reference to some of the proposed changes in the SAR. As I stated in my comments for the Cost Effectiveness Pilot SAR (TPL-001-4) in reference to the six (6) month threshold, “I feel by removing the six (6) month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments". Additionally, I would be concerned that if I include outages less than 6 months that I might be putting multiple outages in the model that might not really overlap (e.g. 2 one month outages that are planned to be in succession may have to both be in the model shown as being outaged). At this point, I will make the assumption that the 'Cost Effectiveness Pilot' data will serve as support in reference to the concerns in FERC Order 786 pertaining to Paragraph 40 six (6) month threshold issues. With that being said, I would suggest that the drafting team take that the industry's feedback into consideration in reference to the 'Cost Effectiveness Pilot Project' into this current project moving forward.

- Spare equipment strategy for steady state analysis

As for the newly proposed language pertaining to Spare Equipment Strategy for TPL-001-4, I would suggest that the drafting team create an additional requirement for this topic and include it the Standard. I feel adding this language into one of the existing requirements will only cause confusion for the industry. Additionally, I feel that the drafting team needs to implement the proposed language in reference to Spare Equipment Strategy in a new subsection in Requirement 2 section 2.4. This would tie it to Requirement 4 section 4.4 which would lead to the industry developing a contingency list expected to produce more severe system impacts for this stability Spare Equipment Strategy Analysis. Additionally, I would suggest adding some rationale language to help explain the drafting team's intents for the proposed language as well as addressing FERCs concerns in reference to Paragraph 89.

- Updating the MOD references

Finally, I agree with the modification to Requirement R1 pertaining to the retirement of MOD-10 and MOD-12 Standards. The Implementation Plan and the modification reflects consistency with the proposed modification suggested in the Standards Authorization Request (SAR).

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - 1	
Answer	No
Document Name	
Comment	
ATC supports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - 6	
Answer	No
Document Name	

Comment	
PacifiCorp supports changes to the draft SAR as listed in 1) and 3) above. However, PacifiCorp does not support the change in change 2): **2a.)** Planned maintenance outages of less than six months in duration are not necessary for long-term annual planning assessments such as TPL-001-4. The annual TPL-001-4 assessments which look in the near-term (years 1 – 5) and long-term (years 6 – 10) planning horizons are reasonable projections of system conditions and are not meant to represent the specific operational type concerns for outages shorter than six months. Risk is based on probability, duration, and severity. The probability and duration of outages less than six months reduces the chance of an event towards zero as the duration gets smaller. Therefore, the industry reviewed and approved six month duration threshold is appropriate for a planning assessment. By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments. Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing. With respect to the concern for evaluation of planned maintenance outages in the seasonal off-peak periods, inclusion of a requirement to perform an assessment of the off-peak seasonal case for planned maintenance outages with durations greater than six months in duration, that extend into seasonal off-peak periods, may be appropriate for the TPL planning assessment. **2b.)** While stability analysis of equipment with a higher probability of complete failure (transformers, circuit breakers) in the absence of spare inventory may identify practical system risks, stability analysis on equipment with significantly lower probabilities of complete failure (series and shunt capacitors, series and shunt reactors, dynamic reactive support), for which maintaining a spare inventory is impractical, may unnecessarily identify deficiencies that have an exceptionally low risk of occurrence. PacifiCorp recommends NERC complete efforts on the Cost Effectiveness Pilot-2016 to establish a reasonable and supportable threshold for the types of equipment that should be subject to the spare equipment requirement based on probability of failure or some other metric to be determined. PacifiCorp believes that implementation of Order 786, paragraph 89, requiring stability assessment of all equipment with a lead time of one year or more without regard to probability of failure would result in significant administrative, capital and operations and maintenance costs without reasonable justification of the reliability benefit that would be realized by those costs. Specifically, maintaining spare inventory for reactive devices with a low probability of failure would create a significant cost burden on utility ratepayers nationwide. Many of these reactive support devices are custom designed and a complete spare would have a high cost for a minimal system reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Regarding Item 1:	

TVA believes changing “address” to “consider” would not align with the recommendations of the SPCS and SAMS. The word “consider” may allow for open interpretation of those recommendations resulting in an increase of scope beyond that which is practical.

While the original FERC Order 754 work was performed with a focus on EHV facilities, there is no language in the SAR that would appear to limit the additional scope of this work in the TPL-001-4 standard to only EHV facilities, for which protection system issues would presumably have a more widespread impact to the BES. We believe the original intent of Order 754 to target EHV Facilities is a proper allocation of resources in order focus attention on Facilities with the most significant impact to the BES.

TVA asks the SPCS and SAMS to poll the industry for cost estimates to implement all work required as a result of making these proposed changes to the TPL-001-4 standard. Requiring redundancy of protective relays as well as DC systems could result in significant facility upgrades, including the construction of a new switch house, for all facilities failing to meet planning criteria. The costs associated with these corrective action plans could significantly outweigh the benefits of protecting against these low probablility events.

Regarding Item 2a:

Planned maintenance outages are considered in operational planning studies which assess the reliable operation of the BPS. Multiple contingency studies for off-peak conditions which consider maintenance outages for a single element plus the subsequent unplanned loss of an additional single element are included in TPL-001-4. These studies support system reliability, system maintenance, and operational flexibility. Moreover, additional transmission studies including planned maintenance outages would typically overlap with operational studies. Therefore, TVA sees a low risk to the reliable operation of the BPS if planned maintenance outages of less than six months duration are not considered in TPL-001-4 studies.

Regarding Item 2b:

If the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events, there is a risk of detrimental impacts to BPS reliability. Generally, the unavailability of long lead-time equipment studied under P0 will be bounded by the existing P1 studies. The unavailability of long lead-time equipment studied under P1 and P2 may not be considered completely bounded by any existing studies. However, given the scope of contingency events already considered, it would be unlikely that critical events would be missed. Therefore, TVA sees a low risk to the reliable operation of the BPS if the unavailability of long lead-time equipment is not considered in stability analysis for P0, P1 and P2 events.

Regarding Item 3:

TVA sees no issues with updating references.

Likes 0	
Dislikes 0	

Response

sean erickson - 1,6

Answer	No
Document Name	

Comment

The omission of significant BES outages lasting less than six months from studies as part of the required annual Planning Assessment in accordance with TPL-001-4 is a low risk reliability concern due to Operation Horizon studies and Outage Coordination (IRO-017). However, a slight modification of R1.1.2 is recommended to state: “Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months, or with a duration of less than six months selected by engineering judgment.” This small change addresses the perceived reliability concern by codifying current industry practice and grants the flexibility for study performance to the Transmission Planner.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

Our review group has some concerns in reference to some of the proposed changes in the SAR. As we stated in our comments for the Cost Effectiveness Pilot SAR (TPL-001-4) in reference to the six (6) month threshold, “we feel by removing the six (6) month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one day outages. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments”. Additionally, we would be concerned that if we include outages less than 6 months that we might be putting multiple outages in the model that might not really overlap (e.g. 2 one month outages that are planned to be in succession may have to both be in the model shown as being outaged). At this point, we will make the assumption that the ‘Cost Effectiveness Pilot’ data will serve as support in reference to the concerns in FERC Order 786 pertaining to Paragraph 40 six (6) month threshold issues. With that being said, we would suggest that the drafting team take that the industry’s feedback into consideration in reference to the ‘Cost Effectiveness Pilot Project’ into this current project moving forward.

As for the newly proposed language pertaining to Spare Equipment Strategy for TPL-001-4, we would suggest that the drafting team create an additional requirement for this topic and include it the Standard. We feel adding this language into one of the existing requirements will only cause confusion for the industry . Additionally, the review group feel that the drafting team needs to implement the proposed language in reference to Spare Equipement Strategy in a new subsection in Requirement 2 section 2.4. This would tie it to Requirement 4 section 4.4 which would lead to the industry developing a contingency list expected to produce more severe system impacts for this stability Spare Equipment Strategy Analysis. Additionally, we would suggest adding some rationale language to help explain the drafting team’s intents for the proposed language as well as addressing FERCs concerns in reference to Paragraph 89.

Finally, we agree with the modification to Requirement R1 pertaining to the retirement of MOD-10 and MOD-12 Standards. Our group reviewed the Implementation Plan and the modification reflects consistency with the proposed modification suggested in the Standards Authorization Request (SAR).

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - 2, Group Name IRC Standards Review Committee

Answer	No

Document Name	
Comment	

(a) Paragraph 40 Directive

The ISO/RTO Council (SRC) Standards Review Committee (SRC) acknowledges that the SDT must address the two outstanding directives from FERC Order No. 786. However, revising TPL-001-4 to address these two directives is unnecessary.

First, Order No. 786 directs NERC to address the concern that excluding planned maintenance outages less than six months in duration in the TPL-001-4 assessment could potentially impact bulk electric system reliability. The SRC agrees that planned maintenance outages should be considered in planning for the reliable operation of BPS. However, outages less than six months in duration discussed in the FERC order are already accounted for in grid planning during the outage coordination process in the operational planning horizon.

Reliability Coordinators (RCs) consider requests for planned maintenance outage submitted by entities in their respective RC areas through their outage coordination procedures. Each RC presently has the authority to deny any planned maintenance outages that would create reliability risks and thereby mitigate any potential risks resulting from planned maintenance outages in its RC area. Reliability Standard IRO-017-1 – *Outage Coordination*, effective April 1, 2017, codifies this practice by requiring RCs to establish a generation and transmission outage coordination process. Consequently, there is no risk to the reliable operation of the BPS if planned maintenance outages of less than six months in duration are not considered in planning studies during one or both seasonal off-peak periods under the TPL-001-4 standard. Also, even if these outages weren't already managed through outage coordination, requiring planners to consider them in transmission planning studies may not be helpful anyway, since a significant number of planned maintenance outages conducted in any given year will not be scheduled or submitted for approval far enough in advance to be incorporated into the planning assessment required under TPL-001-4.

Furthermore, requiring planners to study these outages could result in the identification of costly transmission upgrades to address needs that are expected to be temporary. For this reason, outage coordination is a much more cost-effective option for addressing these outages.

The SRC recommends that the SDT address FERC's directive in Order 786 by requiring that Transmission Planners and Planning Coordinators evaluate planned maintenance outages of less than six months in duration only if the RC for the RC area in which the facilities subject to the Planning Assessment are located does not already coordinate outages for those facilities.

(b) Paragraph 89 Directive*

Second, Paragraph 89 in Order No. 786 directs NERC to "consider" whether it should modify TPL-001-4 to include potential outages of long-lead-time equipment in stability analyses for the P0, P1 and P2 categories identified in Table 1. A revision to TPL-001-4 to address this concern is unnecessary because TPL-001-4 already requires entities to perform stability analyses for the P3 through P7 categories, which produce the same contingency results that stability analyses for P0 and P1 categories would produce assuming unavailability of long-lead-time equipment. While SRC acknowledges that stability analyses of P3 through P7 conditions do not currently include the multiple contingency loss of long-lead-time equipment coupled with the fault conditions described in P2, requiring these additional stability analyses would not be cost-effective because these conditions have historically been very infrequent. For this reason, it is unnecessary and inappropriate to require the proposed analysis.

(c) Single Points of Failure

While we agree with the overall purpose and changes to the SAR, applying the single point of failure testing to the entire BES is a significant excess that will likely end up with increased spending and very little reliability benefit. It should only be required to be performed on certain facilities, like those the FERC Order 754 test used. This would limit the testing to facilities with the potential for instability, uncontrolled separation, or cascading outages. We recommend the goal 1 of the SAR be modified to: “Consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request”, allowing consequential and non-consequential load loss, but not cascading.”

*The IESO does not sign on to the comments addressing the Paragraph 89 directive.

** Please note that MISO and CAISO do not sign on to these comments.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - 1,3	
Answer	No
Document Name	
Comment	

MidAmerican supports the MRO NSRF comments in general with the following additions.

We recommend that the “and open circuit” revision proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies be revised unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs. NERC needs to clearly articulate the BES risk being addressed with the "open circuit" battery monitoring and / or the dual battery banks. If the risk is related to battery capacity, then a dual battery bank mandate may be costly and may not correct the issue. If the risk is an open battery circuit, the open circuit presents a significant risk, and the open circuit monitoring corrects that risk, then the proposal may be appropriate. The reliability benefits of the “and open circuit” revision for battery monitoring may be negligible. According to the 2016 NERC State of Reliability Report, DC systems accounted for 5% of NERC protection systems misoperations between 2011 and 2015 and there is no assertion that the system impacts associated with these protection system misoperations were significant.

We recommend that the “DC control circuitry” proposed for Table 1 footnote 13 be omitted or the system performance associated with P5 contigencies should also be revised, unless it can be demonstrated that the inclusion of this criterion and the existing P5 system performance criteria will significantly improve BES reliability and not lead to unreasonable costs.

Most BES substations have one set of DC control circuity. Recent State of Reliability report did not articulate what impact DC control circuits have on misoperations, so the corrective action of adding dual DC control circuit may have an unreasonable cost for little to no benefit.

We recommend that removing the six-month TPL-001-4 planning assessment threshold is not cost effective and the FERC directive in paragraph 40 of Order No. 786 relating to TPL [illegible] equally effective alternative be proposed to address FERC’s concerns about off-peak conditions. Existing wording in the NERC standard could be identified or clarified to state "outages of more than six-months should include a sensitivity analysis if the outage occurs in the spring and / or fall months."

By removing the six month threshold, FERC opens the door to annual TPL-001-4 planning assessments being performed for one-day outages such as those required for mandated PRC-005-2 relay and maintenance testing. Short term outages are considered in operational planning assessments such as seasonal, next-day, and current-day assessments. Annual Planning Assessments are not operational assessments. In short, annual planning assessments become meaningless as durations become shorter than six months. An annual TPL-001-4 planning assessment represents a reasonable general snapshot of the system assuming all equipment is available and in-service except for the specific contingency performed. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - 2	
Answer	Yes
Document Name	
Comment	

The IESO generally agrees with the proposed changes to the scope of the SAR. Nevertheless, as indicated in our comments on the previous SAR, some of the proposed changes to TPL-001-4 described in the SAR are unclear. Hence, we reserve our judgment on the final scope and the specific changes that will be made to the TPL-001-4 standard. For example:

1. **The replacement of FN 13 with the proposed wording but there is no mention of the placement of the functions or types of relay that will be replaced.**
2. **The meaning of “evaluation of the three-phase faults the described component failures of a Protection System” in the last bulleted proposed change is unclear. Does it mean evaluation of a three phase fault combined with the component failure of a Protection System? This needs to be clarified.**
3. **The SAR is unclear on the fault locations that need to be assessed to meet the following objective:**

“Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts.

Generally, in planning studies, the three-phase faults that are assessed are located on the buses or in their vicinity on the circuits since they have more severe system impact. These faults can still be cleared remotely while the local protection systems experience a component failure.

When the three-phase faults are moved along the circuits there may be locations where the faults remain un-cleared since the protection systems (including the back-up ones) may not be able to detect the faults while they experience a component failure.

Is the intention of the SAR to identify the fault locations where the three-phase faults will remain un-cleared while the protection systems experience a component failure?

The IESO would appreciate the final SAR having more clarity on the above issues.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - 3,5	
Answer	Yes
Document Name	
Comment	

AEP considers the perceived risk of not considering planned maintenance outages less than six months in duration in its studies to be minimal (as previously stated in our comments for the Cost Effectiveness Pilot). At present, our Operations team (in conjunction with applicable RCs) addresses these short duration issues in both real time and seasonal analysis. It would be impractical to address short duration maintenance outages as part of long term planning and modeling. As a result, we do not believe there is a risk-based need to adjust the threshold to less than six months in system models.

As stated in our comments for the previous comment period on this project, the SDT should emphasize both feasibility and practicality in any future requirements regarding system modeling, and the implementation thereof.

Use of the term “include” in the revised footnote 13 may be a source of confusion about whether the other two Protection System components (communication systems, voltage and current sensing devices) are also required by the TPL standard. Rather than “include, we recommend instead using “are” in the revised footnote 13.

We would further recommend not qualifying a NERC Glossary term by footnoting the term “Protection System.” It would be preferable to simply state which components are applicable in Table 1 itself.

While “Single Point of Failure” may have been the original driver for this project, the directives within the SAR now appear to be fairly diverse. Because of this widened scope, the SDT may wish to consider adopting a new project title, one that more clearly specifies their objectives.

The recent comment period for the Cost Effectiveness Pilot for Project 2015-04 (TPL-001-4) included the following guidance: “Project 2015-10: Single Points of Failure TPL-001 from the 2016-2018 Reliability Standards Development Plan is developing a SAR to address potential modifications to TPL-001-4. The results of this pilot will be provided to the drafting team to inform their work on modifying this standard.” The due date for comments for Project 2010-04 was 5/26, which turned out to also be the kickoff date for Project 2015-10. How is it possible that comments for Project 2015-04 could be used to further develop the Project 2015-10 SAR, given that there were no calendar days separating the two comment periods?

Likes 0	
Dislikes 0	
Response	
John Brockhan - 1	

Answer	Yes
Document Name	

Comment

CenterPoint Energy agrees the two (2) outstanding FERC directives from FERC Order No. 786 should be addressed; however, CenterPoint Energy believes the Standard Drafting Team can address the two directives in other ways than modifying Reliability Standard TPL-001-4. CenterPoint Energy comments submitted for the Cost Effectiveness Pilot related to this project included the following:

- CenterPoint Energy does not see risks associated with the current six-month threshold for modeling known outages of generation or Transmission Facility(ies) as specified in TPL-001-4 R1.1.2. Planned maintenance outages of generation or Transmission Facility(ies) with a duration of at least six months are rarely, if ever, scheduled far enough in advance to be included in the Near-Term Transmission Planning Horizon. Shortening the timeframe would only decrease the likelihood of identifying a relevant outage. However, TPL-001-4 R2.1.4 allows for sensitivity analysis to be performed for outages less than six months in duration. If such outages are deemed potentially critical to system reliability, they may be included in the assessment under the current Standard. Furthermore, outages of less than six months reflect operational scenarios and are considered in required operational planning assessments.

- CenterPoint Energy does not believe there is any risk because the impact of the unavailability of long lead time equipment for TPL-001-4 Category P0, P1 and most P2 conditions is already captured as part of the Category P6 stability analysis.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - 10

Answer	Yes
Document Name	

Comment

While Texas RE believes that the scope of the proposed project set forth in the revised SAR appropriately includes the SPSC and SAMS recommendations contained in the Order No. 754 Assessment of Protection System Single Points of Failure report and the FERC directives from FERC Order No. 786, Texas RE remains concerned that the overall scope of this project is too limited. Specifically, Texas RE supports those commenters, such as XCEL, that have suggested that the scope of this project include consideration of any significant issues, reliability gaps, and policy concerns identified through the implementation of the existing TPL-001-4 Standard. Texas RE requests the SDT consider areas in which the existing Standard can be improved, clarified, or expanded as necessary to address reliability issues as they are identified throughout the course of this project.

Consistent with this comprehensive look at the TPL-001-4 Standard, Texas RE also urges the SDT to consider the impact of changes in this Standard on other requirements and definitions. Texas RE previously submitted the comment that it is concerned the proposed language for footnote 13 in TPL-001-4 does not match the NERC Glossary term for Protection System. The language proposed in the SAR for “protective relays” and “DC control circuitry" largely tracks the definition of "Protection System" set forth in the NERC Glossary of Terms. The sole substantive distinction appears to be limiting the general category of "control circuitry" explicitly to "DC control circuitry" consistent with recommendation in the Order No. 754 Report.

In contrast, the SAR (and the Order No. 754 Report) places additional, qualifying language on the definition of "station DC supply" that is not contained in the definition of Protection System in the NERC Glossary of Terms. Specifically, the "Protection System" definition in the NERC Glossary of Terms includes: "Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply)." The SAR (and the recommended language in Order No. 754 Report) qualifies this language by describing "station DC supply" as "single-station DC supply that is not monitored (i.e., not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)."

Texas RE recommends that the SDT use of the existing definition of station DC Supply in the NERC Glossary of Terms. Using consistent language in both Standards would help entities classify their dc supply components in a uniform manner across their compliance program.

Likes 0	
Dislikes 0	

Response

Colleen Campbell - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

(1) We generally agree with the expanded scope and intent of this project, particularly with the modification to requirements and Violation Severity Levels associated with the retirement of MOD-10 and MOD-12 standards. However, there still remains ambiguity in the attributed compliance responsibilities between Planning Coordinators and Transmission Planners in this standard. We recognize the necessary coordination between both functional roles, although clarification should be added to define which functional role is responsible.

(2) We have concerns regarding interpretations of the two directives in Order No. 786 meant to address 1) additional contingency studies to include protection components as "spare equipment," and 2) changes to the six-month threshold to include planned maintenance outages of significant facilities in future planning assessments. There is concern that by removing the six-month threshold, operational planning assessments may be required and create a substantial cost burden on the industry. We ask the SDT to refer to industry feedback associated with the "Cost Effectiveness" project when developing this aspect of the standard and provide sufficient clarification around planning assessment expectations. Regarding studies that include a spare equipment strategy component, we believe the SDT should limit their response to the directive to only substation power transformers before including other BES Elements. Moreover, we believe the SDT should incorporate this additional component in a new requirement and avoid the revision of existing stability analysis requirements.

(3) We sustain our previous concerns that the current applicability of this standard is inclusive to all BES Elements, not the sub-set identified and analyzed as part of the Section 1600 Data Request. The findings identify that buses under 300 kV are less likely to result in an adverse impact to BES reliability based from a Protection System single point of failure. Proposing to collect data for all BES Elements poses an unnecessary administrative burden on registered entities and their models, especially considering that the findings do not support additional analysis under 300 kV. Moreover, analysis results identifying issues which adversely impact the BES reliability could be masked by insignificant concerns.

(4) Within the proposed SAR, we identify several misspellings with words like "consideration" or "cited," and alert the SDT to correct these errors prior to NERC Standards Committee approval.

(5) We thank you for your time in developing this revision to the SAR and the opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Ruida Shu - 1,2,3,4,5,6,7 - NPCC, Group Name RSC no ISO-NE, IESO

Answer	Yes
Document Name	

Comment

In the Section Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?): correct the spelling of consideration, and cited.

In the Detailed Description Section under SAR Information on page 4, in the second sentence "in" should not be struck out.

Likes 0	
Dislikes 0	

Response

Nick Vtyurin - 1,3,5,6 - MRO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Andy Bolivar - 1,3,4,6 - FRCC

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Laura Nelson - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - 1 - MRO,SPP RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project 2015-10 (TPL-001-4) Single Points of Failure

Executive Summary

The Project 2015-10 Standards Authorization Request (SAR) drafting team (DT) thanks everyone who submitted comments on the TPL-001-4 SAR. The SAR was posted for an additional 30-day informal comment period from May 26, 2016, through June 24, 2016. The reason it was posted a second time was to provide industry with the expanded scope of the SAR, which added the two outstanding FERC directives from FERC Order No. 786 and to update the MOD references in the TPL standard.

Comments received covered the System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling Subcommittee (SAMS) Report of FERC Order No. 754, the two FERC directives from Order No. 786, updating the MOD references, a couple of errata changes to the SAR, and a few miscellaneous questions. The SAR DT had a conference call on June 30, 2016, to discuss comments received. The SAR DT made a few minor errata type changes (spelling corrections and moved a couple of sentences around to provide clarity to the purpose of the SAR). In conclusion to the SAR DT conference call, the SAR DT determined that the SAR would be considered final. A redline and clean version of the final SAR are posted on the project page.

There were a good amount of comments received providing justification for the directives, etc. Those comments will be passed to the standards drafting team (SDT) for consideration. Comments received that were not added to the scope of this project, will be addressed during the enhanced periodic review of this standard.

Summary of Comments Received

Below provides a high level summary of comments received for project 2015-10 Single Points of Failure SAR, and the SAR DTs responses. Due to the comment period being informal, the SAR DT is not required to response to comments. The SAR DT thanks everyone for their time and effort in submitting comments.

SPCS and SAMS Report – FERC Order No. 754

Multiple commenters were concerned with the wording change from “address” to “consider” in regards to the SPCS/SAMS report recommendations. The comments suggested that the SDT should follow the recommendation identified and documented by SPCS/SAMS report and that further “consideration” by the SDT is not necessary to meet the FERC directives. There were also comments that included recommendations for changes in specific SPCS/ SAMS recommendations.

The SAR DT concluded that leaving the word “consider” in the SAR would allow the SDT to consider all comments received.

FERC Order No. 786 – Two FERC Directives

The purpose of the SAR DT was to develop the scope for Project 2015-10. The SAR DT concluded that the two FERC directives need to remain a part of the scope, whether that is addressing the directives, providing an equally efficient and effective alternative, or providing justification as to why the directive has already been addressed or is no longer needed. In addition to these three options, FERC directed NERC to consider spare equipment. While some commenters argued that this is not a directive, it is a directive that needs discussion/consideration and a response provided to the Federal Energy Regulatory Commission (FERC).

Spare Equipment Directive:

Many commenters stated that there is very little risk or no risk if stability analysis is not performed for the unavailability of long lead time equipment. The reasoning was based on the following factors: if there is an outage of long lead time equipment, system operations will operate around any problem that might be indicated by their analysis, that the impact of the unavailability of long lead time equipment for TPL-001-4 Category P0, P1 and most P2 conditions is already captured as part of the Category P6 stability analysis, and/or because TPL-001-4 already requires entities to perform stability analyses for the P3 through P7 categories, which produce the same contingency results that stability analysis for P0 and P1 categories would produce assuming unavailability of long-lead-time equipment.

Several commenters had suggestions if the Standard Drafting Team pursued making changes suggested by the directive:

- NERC should complete efforts on the Cost Effectiveness Pilot-2016 to establish a reasonable and supportable threshold for the types of equipment that should be subject to the spare equipment requirement based on probability of failure or some other metric to be determined. Requiring stability assessment of all equipment with a lead time of one year or more without regard to probability of failure would result in significant administrative, capital and operations and maintenance costs without reasonable justification of the reliability benefit that would be realized by those costs.
- As for the newly proposed language pertaining to Spare Equipment Strategy for TPL-001-4, if implemented, suggest that the drafting team create an additional requirement for this topic and include it the Standard in a new subsection in Requirement 2 section 2.4. It is felt that adding this language into one of the existing requirements will only cause confusion for the industry and it would tie it to Requirement 4 section 4.4 which would lead to the industry developing a contingency list expected to produce more severe system impacts for this stability Spare Equipment Strategy Analysis.
- The SDT should limit their response to the directive to only substation power transformers before including other BES Elements.

Duration less than 6 months directive:
Many comments stated that operational studies are already being performed in seasonal assessments, current day and next day studies.

Many comments quoted IRO-017-1, which will be enforceable April 1, 2017; IRO-017-1 R4 requires the Planning Coordinator and Transmission Planner (not TOP) develop solutions for identified issues or conflicts resulting from planned outages in its Planning Assessments for the Near-Term Planning Horizon.

In addition, other comments received indicated the team should consider the following: 1) many comments believed that outages lasting one day would be inappropriate, 2) should off-peak studies be the only seasons required for outage studies, 3) coincide with IRO-017-1 R4, should the outage studies be only in the Near-Term Planning Horizon, and address which planning events have to be included in the outage studies. Example: P1, P2.1, P3 and select EHV planning events.

The SAR DT appreciates all comments received and will ensure the SDT (once formed) receives these comments for consideration.

MOD References

There was general consensus about updating the references to MOD-010 and MOD-012 in Requirement R1 needing to be replaced with MOD-032 due to July 2016 retirement of those standards.

Cost Effectiveness Survey

Many commenters pointed to comments submitted for the cost effectiveness survey. The SAR DT will ensure that the SDT receives all responses for consideration during the modification of TPL-001-4.

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)		
Date Submitted:	October 05, 2015		
SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standards		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Modifications have been recommended to Reliability Standard TPL-001-4 based on the following: Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section

SAR Information

1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.
As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure:
 	
• For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
    ▪ Replace “relay” with “component of a Protection System,” and
    ▪ Add superscript “13” to reference footnote 13 for the replaced term under the “Category” column.
• For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
    ▪ Remove the phrase “or a relay failure[13]” from items a, b, c, and d to create distinct events only for stuck breakers.
    ▪ Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing “a relay failure[13]” with “a component failure of a Protection System[13].”
• Replace footnote 13 in TPL-001-4 with, “The components from the definition of “Protection System” for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.”[1]
• Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

[1] See Order 754 (NERC website) Requests for Clarifications and Responses (http://www.nerc.com/pa/Stand/Order%20754%20DL/Order_754-Requests_for_Clarification_and_Responses_July2013.pdf).

SAR Information
Item 2: Further, references to MOD-010 and MOD_012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards. In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows: • Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments • Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."
Purpose or Goal (How does this request propose to address the problem described above?):
The goal of this SAR is to: 1. Consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"; 2. Address the two FERC directives from Order No. 786; and 3. Update the references to the MOD Reliability Standards in TPL-001.
Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and Results-based Reliability Standards that will: (1) reflect consideration of the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;" (ii) address the two FERC directives from Order No. 786 cited above; and (iii) and update the references to the MOD Reliability Standards cited in TPL-001.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", address the two FERC directives, update the references to the MOD Standards, and

SAR Information
revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard's requirements and measures.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The SDTs execution of this SAR requires the SDT to consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request." This report is incorporated in its entirety into this SAR so as not to unnecessarily repeat or paraphrase the substance of the report. In addition, the SDTs execution of this SAR would consider retirements to requirements under Paragraph 81 criteria.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, email this form to:
sarcomm@nerc.net

NERC welcomes suggestions for improving the reliability of the Bulk-Power System through improved Reliability Standards. Please use this form to submit your proposal for a new NERC Reliability Standard or a revision to an existing standard.

Request to propose a new or a revision to a Reliability Standard			
Proposed Standard:	Project 2015-10 Single Points of Failure TPL-001 SPCS and SAMS recommendations in response to FERC Order No. 754 (TPL-001-4)		
Date Submitted:	October 05, 2015		
SAR Requester Information			
Name:	Philip B. Winston, PE and John M Simonelli		
Organization:	Southern Company and ISO New England, Inc., respectively.		
Telephone:	404-608-5989--primary	E-mail:	pbwinsto@southernco.com--primary
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to existing Standards		☐ Withdrawal of existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Modifications have been ~~identified~~recommended to Reliability Standard TPL-001-4 based on the following: Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single

SAR Information
points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. As such, regarding single points of failure in protection systems, the SPCS and the SAMS make the following recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process identified in the NERC Rules of Procedure: • For Table 1 – Steady State & Stability Performance Planning Events, Category P5: ▪ Replace “relay” with “component of a Protection System,” and ▪ Add superscript “13” to reference footnote 13 for the replaced term under the “Category” column. • For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2: ▪ Remove the phrase “or a relay failure[13]” from items a, b, c, and d to create distinct events only for stuck breakers. ▪ Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing “a relay failure[13]” with “a component failure of a Protection System[13].” • Replace footnote 13 in TPL-001-4 with, “The components from the definition of “Protection System” for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.”[1] • Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

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SAR Information
~~Item 2: In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:~~ ~~Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments~~ ~~Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."~~ Item ~~3~~2: Further, references to MOD-010 and MOD 012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards. In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows: • Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments • Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."
Purpose or Goal (How does this request propose to address the problem described above?):
The ~~primary~~ goal of this SAR is to: 1. Consider the ~~appoint a Standard Drafting Team (SDT) to address~~ recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"; 2. Address the two FERC directives from Order No. 786; and 3. Update the references to the MOD Reliability Standards in TPL-001. ~~."~~
Identify the Objectives of the proposed standards' requirements (What specific reliability deliverables are required to achieve the goal?):
Provide clear, unambiguous requirements and Results-based Reliability Standards that will: (1) reflect ~~condiseration~~consideration of~~standards to address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;" (ii) address the two FERC directives from Order No. 786 ~~citd~~cited above; and (iii) and update the references to the MOD Reliability Standards cited in TPL-001. ~~."~~

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall consider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", address the two FERC directives, update the references to the MOD Standards,~~,"~~ and revise standards, requirements, attachments, Violation Risk Factors, Violation Severity Levels, and implementation plans as appropriate. The SDT shall consider retirements to requirements under Paragraph 81 criteria. In addition, the SDT shall work with compliance on an accompanying RSAW to address each of the standard's requirements and measures.
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The SDTs execution of this SAR requires the SDT to consider~~address~~ the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) identified in the SPCS and SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request." This ~~The SDTs execution of this SAR would, in addition, consider retirements to requirements under Paragraph 81 criteria. The SPCS and SAMS~~ report ~~titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request"~~ is incorporated in its entirety into this SAR~~,~~ so as not to unnecessarily repeat or paraphrase the substance of the report. In addition, the SDTs execution of this SAR would consider retirements to requirements under Paragraph 81 criteria.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☒	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
N/A	N/A

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form

Project 2015-10 Single Points of Failure (TPL-001)

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Friday, August 5, 2016.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2015-10 Single Points of Failure (TPL-001) page. If you have questions, contact NERC Standards Developer, Jordan Mallory (via email), or at (404) 446-9733.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls. Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2015-10 Single Points of Failure

Modifications have been recommended to Reliability Standard TPL-001-4 based on the following:

Item 1: The System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS) conducted a comprehensive assessment of the study of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Item 2: Further, references to MOD-010 and MOD-012 in Requirement R1 would need to be replaced with MOD-032 due to July 2016 retirement of those standards.

In addition, on October 17, 2013 the Commission issued Order No. 786, which included two directives related to TPL-001-4. The two directives are as follows:

- Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.
- Paragraph 89 directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4."

Standard affected: TPL-001-4

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ FRCC	☐ RF	☐ Texas RE
☐ MRO	☐ SERC	☐ WECC
☐ NPCC	☐ SPP RE	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2015-10 Single Points of Failure
Standard Authorization Request (SAR)

Standard Drafting Team Nomination Period Open through August 5, 2016

Now Available

Nominations are being sought for standard drafting team (SDT) members through **8 p.m. Eastern, Friday, August 5, 2016**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in SDT meetings if appointed by the Standards Committee (SC). If appointed, you are expected to attend most of the face-to-face meetings as well as participate in the meetings held via conference calls.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average three full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the SDT sets forth. Drafting teams may have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team are expected to conduct outreach during development, prior to posting to ensure all issues can be addressed.

Previous drafting team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included on the project page and the nomination form.

Next Steps
The SC is expected to appoint members to the team in September 2016. Nominees will be notified shortly after the appointments have been made.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at (404) 446-9733.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | 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.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016

Anticipated Actions	Date
30-day informal comment period with ballot	April 2017
45-day formal comment period with additional ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	December 2017
Board adoption	February 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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

Rationale for Requirement R1:

References to MOD-010 and MOD-012 in Requirement R1 have been replaced with MOD-032, which is now the applicable standard to assemble the network modeling data necessary to meet the TPL-001 requirements. MOD-032-1 superseded MOD-010 and MOD-012, which were retired on 6/30/2016 in the United States.

Rationale for Requirement R1 Part 1.1.2:

In Order 786, Federal Energy Regulatory Commission (FERC) directed NERC to “modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments” (P 40). The Commission clarified that its directive is to “include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages” (P 42). FERC stated that NERC had flexibility in addressing the identified concerns and outlined three acceptable approaches, that include:

1. “eliminating the six-month threshold altogether”;
2. “decreasing the threshold to fewer months to include additional significant planned outages”; or
3. “including parameters on what constitutes a significant planned outage based for example on MW or facility ratings.”

See Order No. 786 at P 43.

Order 786 includes the following additional concerns:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods (*see* P 41);
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand (*see* P 41);
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability (*see* P 41);
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case) (*see* P 42);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (*see* P 44);
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon (*see* P 45).

The change to Requirement 1 Part 1.1.2 eliminates the specified 6 month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term.

Note: The drafting team points out that this is coordination of known outages beyond the Operations Planning.

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-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.

Rationale for Requirement R2 Part 2.4.5:

In Order No. 786, FERC stated that it believed a stability analysis for spare equipment strategy should exist, similar to the steady state analysis under TPL-001-4 Requirement 2 Part 2.1.5 (*see* P 89). The SDT modified the standard to add R2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5.

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, as selected in consultation with the Reliability Coordinator, with known outages modeled as specified 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 studied. The studies 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, Part2.6. 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.

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 studied. The studies shall be performed for the 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.

2.5. 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, Part2.6 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
- 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.

Rationale for Requirement R4 Part 4.6:

The SPF of a non-redundant Protection System component is a relevant reliability concern for the electrical utility industry and have been identified as the cause of significant system disturbances in past years. (*See Industry Advisory-Protection System Single Point of Failure, Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754, Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*). The changes herein clearly establish the TPL-001 standard as requiring corrective actions for Planning Events for which a single point of failure of a non-redundant component of a Protection System, as described by footnote 13. The drafting team took into consideration the recent history of attention given to single point of failure and the tradeoffs with incorporating the 3Ø fault with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing into the existing P5 or similar, Table 1 event. Consistent with the concerns expressed in FERC Order No. 754, the drafting team decided to maintain the 3Ø fault event in the extreme event section of Table 1, while incorporating a specific Requirement R4 Part 4.6 to develop Corrective Action Plan when analysis concludes that Cascading is caused. By featuring the extreme events 2e-2h listed from the stability column of Table 1 in Requirement 4 Part 4.6, this highlights the single point of failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing as having higher risk than other extreme events, but only demanding corrective action if observed to cause Cascading. This is a reasonable balance of likelihood of the event and its consequences. In this way, the drafting team intends for the extreme events 2e-2h listed from the stability column of Table 1 that cause Cascading to require correction, most likely through Protection System modifications, not simply be evaluated for possible actions designed to reduce the likelihood or mitigate the consequences of the extreme event, in accordance with Requirement R4 Part 4.5.

A planner is permitted to use engineering judgment to select the Protection System component failures for evaluation that would produce the more severe system results or impact, and the evaluation would address all Protection Systems affected by the selected component. A Protection System component failure that impacts one or more Protection Systems and increases the total fault clearing time requires a planner to simulate the full impact (clearing time and facilities removed) on Bulk Electric System performance.

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 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.

4.3. 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.

4.6. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:

4.6.1. List System deficiencies and the associated actions needed to prevent the System from Cascading.

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

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 M7 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 Checking
   - Compliance Violation Investigations
   - Self-Reporting
   - Complaints

   1.6. **Additional Compliance Information:** None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Rationale for Table 1 P5 Event and Footnote 13:

The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that may prevent correct operation of a Protection System, including other Protection Systems impacted by that failed component based on the as-built design of that Protection System. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

Changes to the Table 1 P5 event and related footnote 13 are driven by subsequent results of an assessment of Protection System single points of failure in response to FERC Order No. 754. In paragraph 19 of Order No. 754, FERC stated that there is "an issue concerning the study of the non-operation of non-redundant primary Protection Systems; e.g., the study of a single point of failure on Protection Systems." NERC subsequently issued a NERC Section 1600 Request for Data or Information, the results of which were analyzed by the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS). In their 2015 report "*Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*," the SPCS and SAMS considered a variety of alternatives to address the reliability risk posed by single points of failure. SPCS and SAMS concluded that the most appropriate recommendation aligning with Order No. 754 directives and maximizing reliability of Protection System performance included modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SPCS/SAMS report made the recommendations to replace "relay" with "component of a Protection System" in the Table 1 P5 event and replace footnote 13 in TPL-001-4 with alternate wording: "The components from the definition of Protection System for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

This revision to footnote 13 clarifies the components of the Protection System that must be considered when simulating delayed fault clearing due to the failure of a non-redundant component of a Protection System. The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from footnote 13.

The drafting team sought to limit the scope of protective relays which respond to electrical quantities that may be considered non-redundant components of a Protection System that may experience a single point of failure to those relays that are used for primary protection at the local terminal and applied over the element in question. As typical Protection System designs implement backup protective relaying locally and remotely, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability: 1. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. 2. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0. 3. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. 4. Simulate Normal Clearing unless otherwise specified. 5. 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**: 1. Applicable Facility Ratings shall not be exceeded. 2. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. 3. Planning event P0 is applicable to steady state only. 4. 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:** Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event 1	Fault Type 2	BES Level 3	Interruption of Firm Transmission Service Allowed 4	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

<table>
<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>
<tr><td rowspan="2">P5
Multiple Contingency
(Fault plus non-redundant component of a Protection System failure to operate)</td><td rowspan="2">Normal System</td><td rowspan="2">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 rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td rowspan="2">P6
Multiple Contingency
(Two overlapping singles)</td><td rowspan="2">Loss of one of the following followed by System adjustments.[9]
1. Transmission Circuit
2. Transformer [5]
3. Shunt Device[6]</td><td>Loss of one of the following:
1. Transmission Circuit
2. Transformer [5]
3. Shunt Device [6]</td><td>3Ø</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>4. Single pole of a DC line</td><td>SLG</td><td>EHV, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

	4. Single pole of a DC line					

Category	Initial Condition	Event 1	Fault Type 2	BES Level 3	Interruption of Firm Transmission Service Allowed 4	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

Table 1 – Steady State & Stability Performance Extreme Events	
ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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.
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: a. A single protective relay b. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported c. 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 d. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016

Anticipated Actions	Date
30-day informal comment period with ballot	April 2017
45-day formal comment period with additional ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	December 2017
Board adoption	February 2018

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

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

Term(s):

~~Text~~ None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~4~~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.** ~~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.~~

~~6. 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.~~

~~7. 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:~~

~~8. P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~9. P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~10. P2-1~~

~~11. P2-2 (above 300 kV)~~

~~12. P2-3 (above 300 kV)~~

~~13. P3-1 through P3-5~~

~~14. P4-1 through P4-5 (above 300 kV)~~

~~15.~~5. ~~P5 (above 300 kV)~~

~~16. **Background:** Text (**DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have a background section. Going forward standard drafting teams should avoid using this section.**~~

~~17. **Standard-Only Definition:** Text **(DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have standard only definitions. Going forward a standard must provide a justification as to why the standard needs a standard-only definition and cannot be moved to the NERC Glossary of Terms.**~~

B. Requirements and Measures

Rationale for Requirement R1:

References to MOD-010 and MOD-012 in Requirement R1 have been replaced with MOD-032, which is now the applicable standard to assemble the network modeling data necessary to meet the TPL-001 requirements. MOD-032-1 superseded MOD-010 and MOD-012, which were retired on 6/30/2016 in the United States.

Rationale for Requirement R1 Part 1.1.2:

In Order 786, Federal Energy Regulatory Commission (FERC) directed NERC to "modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments" (P 40). The Commission clarified that its directive is to "include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages" (P 42). FERC stated that NERC had flexibility in addressing the identified concerns and outlined three acceptable approaches, that include:

1. "eliminating the six-month threshold altogether";
2. "decreasing the threshold to fewer months to include additional significant planned outages"; or
3. "including parameters on what constitutes a significant planned outage based for example on MW or facility ratings."

See Order No. 786 at P 43.

Order 786 includes the following additional concerns:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods (*see* P 41);
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand (*see* P 41);
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability (*see* P 41);
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case) (*see* P 42);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (*see* P 44);
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon (*see* P 45).

The change to Requirement 1 Part 1.1.2 eliminates the specified 6 month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term.

Note: The drafting team points out that this is coordination of known outages beyond the Operations Planning.

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~~MOD-032 -standard~~s~~, 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)~~ 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 ~~R.~~ 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-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.

Rationale for Requirement R2 Part 2.4.5:

In Order No. 786, FERC stated that it believed a stability analysis for spare equipment strategy should exist, similar to the steady state analysis under TPL-001-4 Requirement 2 Part 2.1.5 (*see* P 89). The SDT modified the standard to add R2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5.

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, as selected in consultation with the ~~as directed~~ Reliability Coordinator, with ~~the~~ known outages modeled as specified 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 studied. The studies 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, Part2.6. 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.

~~2.4.3.~~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.

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 studied. The studies shall be performed for the 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.

2.5. 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, Part2.6 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
- 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.

Rationale for Requirement R4 Part 4.6:

The SPF of a non-redundant Protection System component is a relevant reliability concern for the electrical utility industry and have been identified as the cause of significant system disturbances in past years. (*See Industry Advisory-Protection System Single Point* *of Failure, Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754, Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*). The changes herein clearly establish the TPL-001 standard as requiring corrective actions for Planning Events for which a single point of failure of a non-redundant component of a Protection System, as described by footnote 13. The drafting team took into consideration the recent history of attention given to single point of failure and the tradeoffs with incorporating the 3Ø fault with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing into the existing P5 or similar, Table 1 event. Consistent with the concerns expressed in FERC Order No. 754, the drafting team decided to maintain the 3Ø fault event in the extreme event section of Table 1, while incorporating a specific Requirement R4 Part 4.6 to develop Corrective Action Plan when analysis concludes that Cascading is caused. By featuring the extreme events 2e-2h listed from the stability column of Table 1 in Requirement 4 Part 4.6, this highlights the single point of failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing as having higher risk than other extreme events, but only demanding corrective action if observed to cause Cascading. This is a reasonable balance of likelihood of the event and its consequences. In this way, the drafting team intends for the extreme events 2e-2h listed from the stability column of Table 1 that cause Cascading to require correction, most likely through Protection System modifications, not simply be evaluated for possible actions designed to reduce the likelihood or mitigate the consequences of the extreme event, in accordance with Requirement R4 Part 4.5.

A planner is permitted to use engineering judgment to select the Protection System component failures for evaluation that would produce the more severe system results or impact, and the evaluation would address all Protection Systems affected by the selected component. A Protection System component failure that impacts one or more Protection Systems and increases the total fault clearing time requires a planner to simulate the full impact (clearing time and facilities removed) on Bulk Electric System performance.

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 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.

4.3. 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.

4.6. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:

4.6.1. List ~~s~~System deficiencies and the associated actions needed to prevent the ~~s~~System from Cascading.

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

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**

~~17.1.~~1.1. **Compliance Enforcement Authority:**

~~**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.

~~17.2.~~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 M7 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.

~~17.3.~~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.

~~17.4.~~

~~17.5.~~

~~17.6.~~1.4. ~~1.2~~ **Compliance Monitoring Period and Reset Timeframe:**

Not applicable.

~~17.7.~~

~~17.8.~~1.5. **Compliance Monitoring and Enforcement Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~**17.9.Data Retention:**~~

~~The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.~~
- ~~The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.~~
- ~~The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.~~
- ~~The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.~~
- ~~The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.~~

~~The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.~~
- ~~If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.~~

~~17.10.~~1.6. Additional Compliance Information:

None

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.

R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.
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.	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.	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.	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 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.
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.	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 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 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 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 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 The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient

				voltage response for its System.
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.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents. **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Rationale for Table 1 P5 Event and Footnote 13:

The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that may prevent correct operation of a Protection System, including other Protection Systems impacted by that failed component based on the as-built design of that Protection System. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

Changes to the Table 1 P5 event and related footnote 13 are driven by subsequent results of an assessment of Protection System single points of failure in response to FERC Order No. 754. In paragraph 19 of Order No. 754, FERC stated that there is "an issue concerning the study of the non-operation of non-redundant primary Protection Systems; e.g., the study of a single point of failure on Protection Systems." NERC subsequently issued a NERC Section 1600 Request for Data or Information, the results of which were analyzed by the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS). In their 2015 report "*Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*," the SPCS and SAMS considered a variety of alternatives to address the reliability risk posed by single points of failure. SPCS and SAMS concluded that the most appropriate recommendation aligning with Order No. 754 directives and maximizing reliability of Protection System performance included modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SPCS/SAMS report made the recommendations to replace "relay" with "component of a Protection System" in the Table 1 P5 event and replace footnote 13 in TPL-001-4 with alternate wording: "The components from the definition of Protection System for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."

This revision to footnote 13 clarifies the components of the Protection System that must be considered when simulating delayed fault clearing due to the failure of a non-redundant component of a Protection System. The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from footnote 13.

The drafting team sought to limit the scope of protective relays which respond to electrical quantities that may be considered non-redundant components of a Protection System that may experience a single point of failure to those relays that are used for primary protection at the local terminal and applied over the element in question. As typical Protection System designs implement backup protective relaying locally and remotely, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-

001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

<table>
<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>
<tr><td rowspan="2">P3
Multiple Contingency</td><td rowspan="2">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]</td><td>3Ø</td><td rowspan="2">EHV, HV</td><td rowspan="2">No[9]</td><td rowspan="2">No[12]</td></tr>
<tr><td>5. Single pole of a DC line</td><td>SLG</td></tr>
<tr><td rowspan="3">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="3">Normal System</td><td rowspan="2">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</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>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, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~ non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay~~ 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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11]
    b. Loss of all Transmission lines on a common Right-of-Way[11].
    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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
    e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~d.~~i. 3Ø internal breaker fault. ~~e.~~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
    2. A single communications system, necessary for correct operation of protective functions, 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 through 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:

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.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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 Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and
- 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 protective functions, which is not monitored or not reported
  - 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
  - A single control circuitry associated with protective functions through 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 R4, Part 4.6 and Requirement 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items 2, 3, and 4

Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.

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 R4, Part 4.6 and 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

Do not use this form for submitting comments. Use the electronic form to submit comments on **TPL-001-5 – Transmission System Planning Performance Requirements**. The electronic form must be submitted by **8 p.m. Eastern, Wednesday, May 24, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

   ☐ Yes
   ☐ No

   Comments:

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

   ☐ Yes
   ☐ No

   Comments:

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

   ☐ Yes
   ☐ No

   Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

   ☐ Yes
   ☐ No

   Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2015-10 Single Points of Failure
TPL-001-5

Informal Comment Period Open through May 24, 2017

Now Available

A 30-day informal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements**, is open through **8 p.m. Eastern, Wednesday, May 24, 2017**.

Commenting

Use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the Standards Balloting & Commenting System (SBS) due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will consider all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326

Comment Report

Project Name:	2015-10 Single Points of Failure | TPL-001-5
Comment Period Start Date:	4/25/2017
Comment Period End Date:	5/24/2017
Associated Ballots:	

There were 63 sets of responses, including comments from approximately 180 different people from approximately 129 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

10. Do you have any other general recommendations / considerations for the drafting team?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	1,3,5,6	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Nathan Bigbee	ERCOT	2	Texas RE
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC

					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	CooperativeEnergy	4,6	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Matthew A. Caves	Western Farmers Electric Cooperative	1,5	SPP RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC

					Laurrie Hammack	Seattle City Light	3	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Associated Electric Cooperative, Inc.	Mark Riley	1,3,5,6		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Lower Colorado River Authority	Michael Shaw	1,5,6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE, NYISO and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC

					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC

					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Deborah McEndafffer	Midwest Energy, Inc	NA - Not Applicable	NA - Not Applicable
					Robert Gray	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					Rober Hirchak	Cleco	1,3,5,6	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Jonathan Hayes	Southwest Power Pool, Inc	2	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
					Louis Guidry	Cleco	1,3,5,6	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Steve McGie	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE

					J. Scott Williams	City Utilities of Springfield, Missouri	1,4	SPP RE
					Joe Fultz	Grand River Dam Authority	1	SPP RE
					Thomas Maldonado	Excel Energy	NA - Not Applicable	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Weijian Cong	Santee Cooper	1	SERC
					Chris Wagner	Santee Cooper	1	SERC
					Anthony Noisette	Santee Cooper	1	SERC
PPL NERC Registered Affiliates	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

Leonard Kula - Independent Electricity System Operator - 2

Answer	No

Document Name	
Comment	

There are a few concerns that are introduced by the proposed modification of part 1.1.2:

- Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. However, outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon. Therefore, only outages planned for this timeframe (more than 12-months forward) in advance are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001 and the standard should not involve the RC.

- Moving from a firm threshold to consultation creates ambiguity and potential reliability gaps, and is not an effective means to address the FERC concerns expressed in Order 786. when there are no criteria as to how that consultation is to proceed.

- Replacing the 6-month threshold with a consultation with the RC has the following potential shortfalls:

    1. The TP's/PC's footprint is not necessarily the same as the RC's; there can be several RCs within a TP/PC area, or the other way around. In these cases, who should be consulted and how to reach an agreement if multiple entities are involved? And on what basis should the RC(s) recommend inclusion of certain planned outages?

    2. While the draft standard places an obligation on the TP/PC to consult, there is no mirror obligation on the RC to respond. What if the RC does not respond? Is the TP/PC held non-compliant for having no planned outages included in the planning assessment?

    3. Two entities may be assessing the same system conditions included the planned outages, but they could come up with quite different assessment results due to different risk tolerances or approaches applied in the assessment. If the TP/PC and the RC, or multiple RCs when more than one is involved, come up with different assessment results, whose results should prevail?

To address the FERC directive without the above potential reliability gaps or shortfalls, we offer the following suggestions:

1. Conduct sensitivity testing to identify those planned outages with a duration of more than 1 month but less than 6 months that can have a reliability impact in the planning horizon, and

2. Reflect them in the base model along with those planned outages with a duration of 6 months or longer.

The above can be achieved by revising Part 1.1.2, returning Part 2.1.3 to the existing wording and adding a bullet under Part 2.1.4, as follows:

Part 1.1.2: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months, and those planned outages identified through sensitivity testing in Part 2.1.4 as having a reliability impact in the planning assessment horizon. Part 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. Part 2.1.4: Adding the bullet at the end of the list: • Planned outages of generation or transmission Facility(ies) with a duration of more than 1 month but less than 6 months.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

We do not agree with the concept of removing the 6 month duration outage and we have concerns with the idea of consultation with the Reliability Coordinator (RC). We also disagree with the contention that N-1-1 analyses as specified by P3 and P6 events are not sufficient to address the near term planning horizon reliability concern.

The 6 month known outage duration in the existing standard version, while possibly arbitrary to reliability, does provide some level of objectivity when identifying outages. In contrast, the proposed language is too subjective and open to interpretation. The idea of consulting with the RC to identify known outages, while possibly relevant, adds to the lack of objectivity in identifying known outages and increases the level of complexity in identifying known outages. This idea also does not provide clear ownership for the identification of known outages. In summary, we feel the 6 month known outage duration in the existing standard version balances objectivity and complexity.

As an alternative, we would suggest the SDT investigate the possibility of taking a step back and altering this specific requirement to make it applicable to the TOP and also the TP. The TOP may be in the best position to be aware of known / planned outages in the near term planning horizon, and to be able to identify such outages to the TP. As stated in the rationale, the goal is not to consider hypothetical outages. The TOP may be in the best position to identify known / planned outages, prioritize them in terms of reliability impact, and then them provide to the TP for analysis in the annual near term planning horizon planning assessment.

Regarding the stated contention that N-1-1 analyses as specified by P3 and P6 events are not sufficient to address the near term planning horizon reliability concern, we would disagree. In practice, P3 and P6 should be sufficient as a proxy to assess the impact of an outage followed by another P1 event, as required by Req #2.1.3. The intent of R2.1.3 is to model an outage as an N-0 condition, and then apply and assess a P1 event.

For this same reason, we do not agree with the new proposed Req #2.4.3 (stability analysis considering known outages). In practice, this modified requirement is somewhat redundant with Table 1, P3 and P6 events. P3 and P6 events are applicable for stability analysis. The additional study burden (or compliance burden) may not be commensurate with the expected incremental reliability benefit. If this requirement will be maintained, then the wording should be consistent with the modified requirement 2.1.3.

Finally, It appears there may be a wording error in the modified Req #2.1.3. Req # 2.1.3 should be modified / clarified to state that “P1 events in Table 1, as selected in consultation with the as directed Reliability Coordinator, with the known outages modeled as specified in Requirement R1, Part 1.1.2 (outages selected in consultation with the Reliability Coordinator) under those System peak or Off-Peak conditions when known outages are scheduled.” Our understanding is that the objective is to have the RC consult in the selection of known outages, and not necessarily in the selection of P1 events.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective. The “limited known outages” statement in Question 1 is not part of R1.

We recommend the Requirements 1.1.2 and 2.1.3 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in **BOLD**):

R1.1.2 Known outage(s) of generation or Transmission Facility(ies) as selected **by the Transmission Planner following** consultation with the Reliability Coordinator for the Near-Term **Transmission** Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3. R2.1.3. P1 events in Table 1, as selected **by the Transmission Planner following** consultation with the Reliability Coordinator, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. Alternatively RC should be removed from these Requirements and TP should have the flexibility to select what needs to be studied; as it relates to outages. In addition, this new requirement would result in Transmission Planners (TP) performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	
We are comfortable with the move away from the 6 month minimum duration outage requirement. However, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be limited to known outages for the time period beyond 12-months from the current date to year 5. Since the proposed revision uses the term 'Near-Term Planning Horizon' this would inadvertently include the first year which is an Operational Planning responsibility. The TPL-001 standard is intended for Transmission Planning, not Operations Planning, and is focused on analyzing the transmission system for necessary upgrades to maintain reliability. These upgrades require well over 12-months to plan, design, permit, and construct. Required analysis of outages planned in the timeframe of less than 1 year from the current date should be the exclusive responsibility of Operations Planning through reliability standards such as IRO-017 which are intended to cover the Operations Planning time horizon	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	No
Document Name	
Comment	
SDG&E reads the sentence, "in consultation with the Reliability Coordinator", to mean that the Transmission Planner and Planning Coordinator would be required to have the list of maintenance outages assessed approved by its Reliability Coordinator [PeakRC]. This would shift some of the responsibility for TPL-001 from the TP/PC to the RC and it is unlikely that an RC would approve a list of know outages which did not include all know outages (a subset of the complete list) without first assessing each outage on the list. Requiring the RC to approve ***all*** *known outages within its territory will place an unreasonable burden on the RC and the TPs/PCs. SDG&E recommends removing the language, "in consultation with the Reliability Coordinator" from 1.1.2 and 2.1.3.* *SDG&E agrees with the addition of section 2.4.3. The original language in requirement R1.3.12 read, "Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed." This language is reflected in 2.4.3 and serves to limit the study of known – planned - outages to those periods when maintenance is typically done (Off-peak load periods). It also captures known outages of long duration which may not be completed before the next peak load period occurs (System peak load).*	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	

While AEP does not object outright to the proposed change that the outages be determined as a result of consultation between the PC/TP and RC, we wonder if such an approach might perhaps lead to inconsistent application and methodologies across the system? The Standards Drafting Team may wish to consider this possibility themselves, and weigh the likelihood of such inconsistencies. The text "as selected in consultation with the Reliability Coordinator" has been inserted at the wrong location within R.2.1.3. As currently proposed, it appears that it the P1 events, rather than the outages themselves, which are being selected in consultation with the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees with moving away from the 6-month fixed duration outages. BPA does not agree that consultation with the Reliability Coordinator is necessary. BPA believes the extra coordination would be burdensome and would not provide additional value. BPA already participates in a 45 day regional outage coordination process. BPA believes that this regional coordination process is sufficient to identify the outages to meet Requirement 1, Part 1.1.2.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
TVA does not agree with the change to Requirement 1, Part 1.1.2. The Planning Coordinator and Transmission Planners have the capability and understanding to select outages that should be included in their Near-term Planning horizion. For those Reliability Coordinators with a significant number of Transmission Planners and Planning Coordinators in their footprint, this requirement change would add a significant burden on the Reliabiltiy Coordinators without benefit to the process. The focus of the Reliabililty Coordinator is in the real-time to one year horizon, Transmisison Planning should be focused on the one year to five year horizon. If there needs to be an entity to oversee and advise the TPL studies conducted by the Transmission Planner it should be the role of the Planning Coordinator. In addition, these studies are already being performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. Even if problems were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an op guide. The operational cases have a more accurate near term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take significant new effort and time to complete.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	
JEA appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 issued on Oct. 17, 2013, Paragraph 40. This standard is applicable only to PCs and TPs per the Applicability section, thus RCs are not under any compliance burden. So what course of actions can the PCs and TPs take to show compliance if they do not receive due cooperation/consultation from the RCs? Please see the comment under #5 below as well. The changes add extra burden on the PCs and TPs for compliance on which they have no control. Additionally, the outage coordination seems to be more of an Operational Planning issue (for next-day studies up to six months) than a Transmission Planning issue (one to ten years studies). No matter how far ahead PCs and TPs study the system, when it comes to the Operation horizon, the outages	

need to be studied again with a more realistic system conditions than in the Planning Horizon. Hence any specific analyses performed by PCs and TPs for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon.

Besides, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TPs and PCs have no other allowed mitigation plans, such as operational procedures, except to recommend Corrective Action Plans which result in capital improvement projects. Thus planning for outages in the Near-term Transmission Planning Horizon will only result in capital investment that effect the rates of our customers unnecessarily.

Instead standard **IRO-017 – Outage Coordination** seems to be a much better place to have this directive from Paragraph 40 of Order No. 786 addressed.

Suggestion: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address this in a future revision of IRO-017

Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	Project 2015-10 TPL-001-5 CBPC.docx
Comment	

Corn Belt agrees with the SPP Standards Review Group and its clarification of an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group states that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also found the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit.

Corn Belt agrees with the SPP Standards Review Group that the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, the reference to the number of additional cases and the associated seasons that could be required. Corn Belt agrees with the SPP Standards Review Group suggested proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.

Also concerned that this could significantly increase the number of near term cases created and studied and add significant work load to tune L&R for these cases. Concern this will significantly increase PC/TP study work load without benefit due to undetermentant amount of outages that need studied. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. Concern this change will result in significant wasted time and effort to produce results that won't ultimately be used because the same outages will be restudied in ops horizon.

> Outages of concern to be studied separately. Base case assumptions.[A1]
>
> Suggested Language:[A2]
> R1.1.2 Known critical 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.

Firmly disagree with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	No
Document Name	
Comment	

Outage studies — for planned or unplanned outages of any duration — are handled now in the operational horizon with RC coordination. The duration of the outage shouldn't matter. This change would create unnecessary additional work.

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA agrees with the intent to include significant impactful outages that are important to evaluate ahead of what is covered in the Operations Horizon, but we need to ensure that the language change to Requirement 1, Part 1.1.2 supports this intent. It is essential that the scope of outages be limited to significant planned outages that are not hypothetical in nature. Otherwise, there is a concern that this could significantly increase PC/TP study work without an appreciable benefit due to an undeterminant amount of outages that need to be studied. Outage scheduling changes could occur potentially leading to the results from the R1.1.2 analysis becoming irrelevant as it gets closer to when the outage will actually occur (Operations Horizon). These outages will need to be restudied in the Operations Horizon using more accurate information anyway. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. There is a risk that the proposed language change to R1.1.2 could lead to it being left wide-open regarding what should be included in a Planning model because there are no parameters on what constitutes a significant planned outage.

WAPA disagrees with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Suggested Language (add a qualifier to specify these outages should be critical/significant in nature and leave the ultimate decision upon what constitutes a significan planned outage to the PC/TP per R1 that, "shall maintain System models… to complete its Planning Assessment"):

Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	

Idaho Power disagrees with the concept to move away from the 6 month outage duration. While it is reasonable to include known outages that will occur in the time horizon being studied, it's unclear how the consultation with the RC will work; in general, the RC is rarely aware of outages 1 to 5 years out unless they are long term (lasting more than 6 months).

Likes 0	
Dislikes 0	
Response	

Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1

Answer	No
Document Name	
Comment	

PGE agrees in principal to coordinating with the RC when selecting outages to study as part of the TPL assessment. The removal of the 6 Month duration, however, without new language to define the criticality of planned outages to be studied is not recommended. Planned projects require many outages for completion, some as short as a few days and some much longer. The full list of required outages cannot be known in the planning horizon. Without specific criteria for identifying outages, the RC cannot know the criticality without study, creating a paradox. This proposal could potentially require the creation new case for every identified outage, regardless of outage duration, significantly increasing the work required to complete the TPL analysis. It has been PGE’s experience that a single construction outage rarely results in significant impacts to the BES. When several outages overlap, the BES may be affected. It is not possible to know how outages will overlap in the planning horizon. This risk is managed in the Operations Horizon in the NW via the 45 Day Outage Scheduling Process.

The additional requirement to study planned outages in the dynamics analysis section 2.4.3 will be extremely burdensome and not necessary for similar reasons to those stated above.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS supports retaining the 6 month threshold as anything less than 6 months may only be a temporary system configuration. The TPL Assessment is a planning assessment and should be limited to standard system configurations. The Operating horizon should address anything occurring in less than 6 months. On a case by case basis outages of shorter duration could be included if mutually agreed upon by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs).	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	

Outage schedules are market-sensitive information. Outages planned for later years often are not posted to OASIS due to the volatility of outage scheduling long in advance of the outage. Putting these outages in models which are then shared with other Transmission Planners risks improperly sharing this market sensitive information outside the OASIS process.

While we recognize the importance of coordinating outage information, long-term planning models are generally outside the timeframe of interest to Reliability Coordinators. Without a compliance requirement to be involved in the process, it is likely that RCs will not give this process the attention it needs to be effective. The requirement to consult with the RC should be either removed, or a requirement should be added for RCs to respond to these consultation requests in a timely fashion.

Transmission Planners need the leeway to model outages appropriately. It is possible to have mutually exclusive outages which can be applied to a model based on the peak or off-beak conditions being modeled. For instance, outages may be scheduled for multiple sections of a line as part of a line reconductoring project. While all of these outages may fall in the same off-peak season, only one of them will be in effect at a time. It is also within the RCs authority to cancel planned outages that degrade the reliability of the system. Developing projects for outages that are optional would not be appropriate unless it was determined that the planned outage was both required and not feasible without reliability challenges deemed to significant to allow by the RC. TPs should be explicitly allowed to select outages based on criteria beyond the scheduling of the outage in order to accurately model the effects of the outage plan.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement which was never intended.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
The following answers to all the questions are from our City Light subject matter experts: Comments: The PCs and TPs are responsible for complying to the TPL-001-4 standard. RCs are under no obligation to comply with same and have no reason to have input on planning horizon outages (more than 1 year out) that are outside the operations planning horizon (less than 1 year out). As indicated in response to question 5, it is agreed that no additional entities should be added to the applicability of this standard, including the RC, who is focused on the operations of the system. A gap in communication between PCs/TPs and RCs may put the PCs/TPs in a position where compliance for this standard are not met. In the planning horizon, the PC and TP would be the more appropriate entities to be able to identify significant outages. When planning for outages in the near-term planning horizon, considering outages that are longer than 6 months is appropriate. If the 6 month duration is removed, there are too many planned outages that occur regularly that may be identified to be included in the study even when it is not necessary and would be studied in the outage coordination process. Suggestion: Keep the language in the R1.1.2 of the TPL-001-4 standard.	
Likes 0	
Dislikes 0	

Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, and resilient at all times in the future given the lead times associated with making necessary system improvements. Adequacy, reliability, and resiliency include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single transmission facility has been removed from service for planned maintenance. All transmission facilities require planned outages from time-to-time to facilitate i) maintenance, testing, and/or repair work that cannot be performed hot; ii) to facilitate protection scheme testing, maintenance, and upgrades on facilities with non-redundant protection; iii) to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility; or iv) for other purposes. Therefore, the eventual occurrence of a future planned outage on any transmission facility is certain and “known”, not “hypothetical”, only the timing and duration of the future outage could be considered uncertain or “hypothetical”.   If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy and resiliency to accommodate planned maintenance requirements in general.

In FERC Order 786, the Commission indicated the following at PP 41:

“We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.” (emphasis added)

It is “known” that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the prudent planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient resiliency to accommodate planned maintenance outages during off-peak periods that will be required regardless of whether or not such activity has been scheduled.

Direction on ensuring the system could me TPL criteria for future potential planned outages was previously given in an interpretation to TPL-002 and TPL-003. Please consider this, as its intent appears to be lost in forming the TPL-001-4 standard.

http://www.nerc.com/docs/standards/sar/MISO_Interpretation_TPL_Revised_20Mar08.pdf

http://www.nerc.com/files/TPL-002-2b.pdf Pg 11

"The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards."*

While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and resiliency to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate an outage or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedules planned outages when they are needed without sacrificing reliability or load continuity.

A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This scenario would be evaluated only for non-peak conditions. The idea here is that the system does not need to be planned to support planned maintenance during peak load conditions, since those conditions represent a very small percentage of time. However, under periods where planned maintenance is typically performed (e.g., shoulder peak and light load conditions, etc.), the system should be planned to accommodate the planned outage of any one system element (transmission or generation) while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. This additional aspect of the P3 and P6 contingencies will require an adjustment to the traditional contingency definitions to facilitate service to all loads for the planned maintenance outage element in accordance with how the system would be switched for planned maintenance. For example, the planned maintenance outage of a network transmission line section with tapped distribution substations served by the line would be switch-to-switch (only the section between two adjacent distribution substations that required maintenance would be taken out of service) instead of breaker-to-breaker to ensure all

load could continue to be served during the planned maintenance outage. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, resilient, and reliable in the future.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: Santee Cooper appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786. This standard is applicable only to Planning Coordinators and Tranmission Planners per the Applicability section and as such the Reliability Coorindators should not be placed under any compliance burden. Adding the Reliability Coordinator adds an extra burden on the PCs and TPs to demonstrate compliance. Order 786 does not require the Reliability Coordinator to be consulted with on outages. The requirement to consult with the Reliability Coordinator should be removed from this standard. Recommend to keep the existing language of R1.1.2 the same as in the current approved version. Outage coordination is studied in the operational planning horizon in accordance with IRO-017 – Outage Coordination. No matter how far ahead PCs and TPs study the system, when it comes to the operational planning horizon, the outages need to be studied again with anticipated system conditions. Any specific analyses performed by PCs and TPs for the outages in the Planning Horizon do not provide much value for Real-time operations.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No

Document Name	
Comment	

PacifiCorp agrees that a Transmission Planner in coordination with the Reliability Coordinator should determine which known outages should be studied, but requests the drafting team to provide more clearly defined guidance to both the reliability coordinator and transmission plannner as to the kind of outages that should be considered for this analysis. For example, a known outage of a generator greater than 500 MVA should be studied or a known outage of a transmission element with a facility rating of 800 MVA or higher should be studied. In addition to providing thresholds for outages to be considered, PacifiCorp believes that the drafting team should also consider FERC's option of reducing the duration from 6 months to either 3 or 4 months, otherwise there would be no distinction between momentary outage as simulated per the P3 and P6 event, as compared to a known outage that can change dispatch patterns and expose the system to a reliability issue.

PacifiCorp believes that performing a known outage analysis for year one or year two case provides benefit for both operational and planning horizon, but performing the known outage analysis for a 5 year case does not provide any benefit as the system conditions could have changed significantly and are not known while performing the TPL assessment.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

We respectfully disagree with several aspects of this proposal. In the first place, we believe that planned/approved outages of significant duration, if any, should be evaluated in the planning horizon for those outages that would occur in the planning horizon. These outages should include any seasonal outages or outages that would last for a majority of the season to be studied. We would agree to let the Planning Coordinators/Transmission Planners decide if the outages would be appropriate to include in the models required for assessement. However, from our perspective, transmission equipment outages are not planned beyond the operating horizon and are not planned for peak-load periods which drive system expansion plans. Daily or weekly outages of transmission equipment for maintenance or construction are planned for off-peak periods, and are typically not approved for beyond the

operating horizon. Therefore, the majority of the these outages need not be considered for the planning assessment and should not be a part of TPL-001-5. While it is true that owners of generation equipment plan outages for beyond the operating horizon, these outages for nuclear refueling or regular turbine/generator maintenance are also planned for non-peak load periods. Some transmission maintenance outages are also planned, in the operating horizon, to take advantage of these generation equipment outages to minimize the opportunities for transmission service curtailments. Operations Planning personnel spend hours evaluating transmission system performance considering the various construction and maintenance activities that are proposed to keep the system functioning. These evaluations are performed in the operating horizon for implementation in the operating horizon, and utilize generation redispatch and transmission system switching as part of operating guides to work around the planned outages while considering the next worst single contingency event. We do not believe that the intent of the corrective action plan is to include temporary operating guides that are needed to facilitate near-term construction and maintenance outages. Secondly, if the intent of the proposed change is to address maintenance outages, then the requirement for R2 should be changed to specify the need to study maintenance outages during the times that the maintenance outages would be performed. While it is true that P3 and P6 planning events will not cover all maintenance outages plus planning events for beyond N-2 planning, it would cover a significant reliability concern during these off-peak periods. Thirdly, the Reliability Coordinator (RC) is not an applicable functional entity for this standard. Therefore, we believe that involving the RC in the planning assessment and development of the corrective action plans for long-term system development is inappropriate. The RC has a near-term focus and is often unaware of needed longer-term system developments that are needed to meet TPL-001 planning requirements, as well as local transmission planning criteria. Many of the outages that RCs must address are required for construction or restoration, and likely would not be applicable for future operating conditions.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
While we agree with the move away from the 6 month minimum duration outage requirement, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be known outages for the time period beyond Operations Planning time horizon. Required analysis of outages planned in the timeframe within Operations Planning time horizon is addressed in Reliability Standard IRO-017 which are intended to cover the Operations Planning time horizon. Our suggested wording of Requirement 1.1.2 is shown below.	

1.1.2. Known outage(s) of generation or Transmission Facility(ies) as selected by the PC/TP in consultation with the Reliability Coordinator for the Near-Term Transmission Planning Horizon beyond Operations Planning time horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	

The new requirement is open ended and may result in Transmission Planners (TP) performing almost a "real time" operations analysis (i.e. what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (the purpose of TPL-001). NERC IRO-017 *Outage Coordination* was set up for that purpose, and this proposed change would represent a spillover from IRO-017. The TP would be required to develop a Corrective Action Plan for system outages.

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective. The "limited known outages" statement in Question 1 is not part of R1.

We recommend the Requirements 1.1.2 and 2.1.3 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in RED):

R1.1.2 Known outage(s) (for the time period beyond 12-months into the future) of generation or Transmission Facility(ies) as selected by the Transmission Planner or Planning Coordinator following consultation with the Reliability Coordinator for the Near-Term Transmission Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

R2.1.3. P1 events in Table 1, as selected by the Transmission Planner or Planning Coordinator following consultation with the Reliability Coordinator, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

Alternatively, RC should be removed from these Requirements and TP or PC should have the flexibility to select what needs to be studied; as it relates to outages.

In addition, this new requirement would result in Transmission Planners (TP) or Planning Coordinator performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001. While we agree with the move away from the 6-month minimum duration outage requirement, we feel strongly that the outages selected by the PC/TP in consultation with their RC should be known outages for the time period beyond 12-months from the current date. Required analysis of outages planned in the timeframe of less than 1 year from the current date should be the exclusive responsibility of Operations Planning through reliability standards such as IRO-017 which are intended to cover the Operations Planning time horizon. Our suggested wording of Requirement 1.1.2 is shown below.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
While Peak agrees that the six month outage threshold should be changed for the reasons described in the rationale provided for proposed requirement R1, part 1.1.2, Peak disagrees with the proposed mechanism of addressing the issues set forth. In accordance with IRO-017-1 requirement R1, the RC is required to have an outage coordination process for transmission and generation outages in its RC Area. This requirement is applicable to the Operations Planning Time Horizon, which is typically considered to be the Time Horizon over which the RC/TOP has assessment responsibility. Outages that are planned further in advance of the Operations Planning timeframe are addressed in the PC/TP's Planning Assessments. These outages are outside the RC/TOP's timeframe of assessment responsibility and are inside the PC/TP's timeframe of assessment responsibility. IRO-017-1 requirement R4, which requires the PC and TP to jointly develop solutions with its respective RC(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, serves to connect the dots from planning to operations and serves as a valuable hand-off from planning to operations. The requirements in IRO-017-1 were specifically written this way to accomplish the dot-connecting objective. Regarding outages in the planning horizon, the RC has no knowledge of – or responsibilities for – outages that fall outside the Operations Planning Time Horizon. The proposed requirement as written implies that the RC is to have data for planned outages in the Near Term Transmission Planning Horizon and perhaps even to perform some degree of screening to determine which of those planned outages should be included in the PC/TP's Planning Assessments. This not only results in an additional burden for the RC, but also creates an environment where the RC may have (or be perceived to have)	

some degree of responsibility for activities that take place outside of its timeframe of responsibility. Accordingly, Peak does not support the proposed approach of having the PC/TP consult with the RC to determine which outages should be included in the PC/TP's Planning Assessments.

By default, proposed requirement R1.1.2 requires the RC to "do something" in order for the TP/PC to be compliant – which in effect is a requirement for the RC. Peak believes this is not a good approach for writing standards. If the RC does not participate in this consultation, or if the consultation is "weak", is the PC/TP faced with a potential compliance ramifications? If such is the case, is the RC subject to any compliance ramifications? Unfortunately, this same issue exists with currently approved IRO-017-1 requirement R4. While such requirements have a good reliability intent, there are better ways of writing requirements to achieve that desired intent. Bottom line, Peak believes there is a better way.

Peak believes that there are alternative solutions that may better address the issues stated in the proposed R1 rationale box.

One approach could be to create a requirement in TPL-001 or IRO-017 for the PC to develop and implement a process for determining the outages to be included in the PC/TP Planning Assessments for the Near-Term Transmission Planning Horizon. The requirement would have no mention of the RC, so as to not create any implied responsibilities for the RC. That said, if a given PC's process happens to include involvement from the RC, and the RC is agreeable to participating, then so be it. However, Peak does not believe that the RC's involvement under the auspices of "consultation" should be stated in a requirement applicable to PC/TPs. There are pros and cons with this approach.

If an objective is to create requirements to better bridge planning with operations and to have the RC provide input to the selection of outages to be included in Planning Assessments, another approach would be modify IRO-017 to create a requirement for the RC to document the criteria that the PC/TPs shall use to determine which planned outages, at a minimum, need to be included in TP/PC Planning Assessments for the Near Term Transmission Planning Horizon. TPL-001 can then have a requirement to include, at a minimum, the outages that meet the RC's criteria. With this approach, the RC's responsibility would stop with defining the criteria for the PCs to use at a minimum. The RC would not be required to consult with PC/TPs beyond that.

Alternately, the TPL-001 standard itself can explicitly specify the criteria for outages that need to be included in the Planning Assessments for the Near Term Transmission Planning Horizon. If an outage of six month duration isn't the right answer, perhaps the standard can find the right answer and include it in the standard rather than getting the RC involved in the decision process.

Additionally, given the high number of PCs and TPs in the Western Interconnection, it is impractical for Peak as an RC to consult with PC/TPs in the determination of outages that should be included in the PC/TP's Planning Assessments. Given this situation, Peak would be in favor of the second or third potential solutions described above.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	No
Document Name	
Comment	
NVE suggests changing Requirement 1, Part 1.1.2 to known outages selected by the Planning Coodinator/Transmission Planner. The transmission planner should provide justification for the selection of the outages which could include consultation with the RC or other internal processeses.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
No, Part 1.1.2 should be removed altogether since IRO-017 already cover planned outages in the operations planning and near-term planning horizons.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) We are concerned that the proposed changes could require applicable entities to administratively demonstrate communication, coordination, and selection processes for proof of consulting with their RC. This would include a PC-TP selection process that justifies the exclusion of RC-identified outages. The references to Requirement R2 are also cumbersome and require the applicable entity to review other aspects of the standard to determine how to comply with this requirement. (2) We believe the proposed modifications could be simplified to include references to NERC Reliability Standard IRO-017-1, which already requires PCs and TPs to jointly develop solutions for identified conflicts in their Planning Assessments for the Near-Term Transmission Planning Horizon. Near-Term Transmission Planning maintenance schedules identified by TOs and GOs are provided to TOPs and BAs, and then shared with their respective RC, per Reliability Standard IRO-017-1. The RC may have knowledge of future Facility maintenance schedules beyond the Near-Term Transmission Planning Horizon, but only on a voluntary basis as provided by an external entity. We propose this alternative change instead: “Known generation and Transmission Facility outages included in Near-Term Transmission Planning Horizon Planning Assessments for its respective Reliability Coordinator outage coordination process.”

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy agrees with FERC and NERC that analysis of transmission and generation outages is a critical function that must be performed with appropriate expertise and knowledge to ensure facility outages of limited duration do not create operational concerns. Duke Energy disagrees that these requirements should be included in a planning related standard (i.e. TPL-001). The related requirements would be more appropriate in an operation related standard (e.g. IRO-017). Duke Energy believes an equally effective and efficient solution to address FERC Order 786 can be obtained by modification of an operationally focused standard. Transmission planners ought to be a resource to assist the work in such a standard, but should not have primary responsibility. Inclusion in the proposed standard of the RC in the “consulting” role of making the determination of what outages must be studied is indicative of the fact that operational considerations are key to proper assessment – from what outage to study under what conditions to what are acceptable actions to take to allow the outage to proceed. Operational personnel have the appropriate mindset, tools and background knowledge to perform the assessment and when necessary, be supported by planning personnel. The TPL-001 standard is intended to ensure sufficient infrastructure is planned to provide the operators a robust enough system to operate reliably under the varying conditions they will experience. It would almost never be appropriate to make infrastructure upgrades to alleviate reliability concerns that appear due to outages of limited duration. Transmission planners are expected to evaluate the feasibility of implementation of projects they propose and the outages that will be required as part of developing their TPL-001 corrective action plans. However, the decision to allow outage of any facility for any reason lies with transmission operators. Operating conditions and outage schedules change with time and outage plans must be continuously re-evaluated and revised, up to the very day they are to begin. Conditions change so much that it is not useful nor necessary to study outages throughout the entire Near Term Planning Horizon. The Operating Horizon, usually considered to be 13 months, is a reasonable timeframe for evaluation of proposed outages.

Transmission operators are most knowledgable of system transmission and generation outage plans, how they have changed, the interactions between them, the expected system conditions, what are acceptable compensatory actions for reliability concerns…. and have final authority over allowing an outage to take place. Also, performance of the analysis of outages' impact equips transmission operators to be able to make acceptable last minute decisions regarding outages when expected system conditions change, as they often do. It would be inappropriate to expect transmission planners to make those decisions or to rely to a large extent on analysis that transmission planners had performed in the past for maintenance of system reliability in the operating horizon.

If the requirement is to remain in the TPL standard it should be modified to make it clear that the RC will determine what outages are to be studied and the period to be studied reduced from the full Near-Term Planning Horizon.

Wording in the standard or the technical guidance document should be provided to clarify the RC's role. For example: Outages with a duration greater than 2 months of the same seasonal period or of facilities deemed critical to the operation of the system, in the judgment of the RC, must be evaluated. Such language ensures that the duration of the outage is significant enough to warrant evaluation beyond what will be done under normal operational planning practices. It also allows the RC to exercise their knowledge and expertise when appropriate.

The period that evaluation of such outages should be shortened to the first two years of the Near-Term Planning Horizon. Evaluation of outages further into the future than that will likely result in unnecessary studies being performed by the PC/TP due to changes in outage plans. No reliability gap is created because the outages will be studied prior to their execution.

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	

Although LES agrees with the move away from the 6 month duration outage, we're concerned that the selection of known planned outages in consultation with the RC unduly complicates the process. Recommend removing the RC from TPL-001-5 in consideration that the TP and PC are already performing these assessments and are capable of making a judgment of including or not including a known planned outage.

Additionally, it is unclear whether R1 is intended to be directed towards the annual MOD-032 model development (e.g., where the PC and TPs jointly develop modeling data requirements), or if the selection of known planned outages is solely part of the Planning Assessment.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE appreciates that Standard Drafting Team's (SDT) efforts to develop a flexible and workable Transmission System Planning Performance Requirement Standard. However, Texas RE is concerned that the current proposal does not properly implement the Federal Energy Regulatory Commission's (FERC) directive in Order No. 786 to include planned outages lasting less than six months in some fashion in the planning process and could result in reliability gaps.

In doing so, FERC provided clear guidance that its intent was to expand the number of planned outages required to be including in TPL-001 planning assessments. Specifically, while recognizing NERC has the flexibility in implementing its directive, FERC specifically enumerated several acceptable approaches that all would result in the inclusion of additional planned outages in the planning process. FERC wrote: "we believe that acceptable approaches include eliminating the six-month threshold altogether; decreasing the threshold to few months to include additional significant planned outages; or including parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings." Each of these scenarios share a common trait: the number of planned outages included in required transmission planning analyses will increase.

In contrast with FERC's examples, the proposed TPL-001-5 could result in the inclusion of fewer planned outages in the transmission planning process. In particular, the proposed standard requires only the inclusion of known generation or Transmission outages that are "selected in consultation with the Reliability Coordinator [RC] for the Near-Term Planning Horizon . . ." Under the proposed TPL-001-5, therefore, Transmission Planners (TPs) and Planning Coordinators (PCs) could elect to exclude not only all planned outages with a duration of less than six months, but also additional planned outages with planned durations greater than six months after consultation. While FERC recognized that NERC should retain flexibility in implementing its directive, the current proposal appears to run counter to FERC's intent to ensure that a broader category of planned outages that could result in impacts to the Bulk Electric System (BES) during peak and off-peak periods are examined to ensure they can occur without the loss of inconsequential load or detrimental impacts to system reliability.

The proposed standard revisions further exacerbate this problem by inserting the same "selected in consultation with the [RC]" language into the scope of the annual Planning Assessment requirements set forth in TPL-001-5 R2.1.3. Under the existing TPL-001-4, Qualified Planning studies must include models of the loss of generators, transmission circuits, transformers, shunt devices, and single poles of a DC line. These P1 contingencies must all be modeled to ensure there is no inconsequential loss of load and no interruption of firm transmission service. In contrast, the revised TPL-001-5 permits TPs and PCs to omit P1 contingencies. Specifically, the proposed standard only required including P1 contingency events selected in consultation with the RC. Presumably, the SDT included this language to flow through its proposed modifications to the six-month threshold in TPL-001-5 R1. In doing so, however, the SDT has again broadened the potential modeling exceptions in R2 beyond merely certain planned outages to permit waivers of all P1 contingencies. As such, it is possible that a TP and/or PC may inadvertently fail to study a significant P1 contingency. However, if that event was not identified in the P1 contingency event "selected in consultation with the [RC]", the TP and PC would still have conducted a qualified Planning Assessment. This result is wholly inconsistent with TPL-001's goal of ensuring BES reliability following a wide range of probable contingencies. Texas RE suggests the gap be addressed by the standard requiring that all P1 events are included in the qualifying studies with known outages modeled.

It is also important to note that the "consultation" model envisioned in the proposed standard could lead to a number of other issues. In addition to the problems regarding the inclusion of P1 contingencies, Texas RE points out that in many instances the relevant PC and RC are the same entity. In the ERCOT region, the same entity is responsible for both functions and develops the initial system-wide transmission models. Accordingly, the proposed standard appears to contemplate this entity "consulting with itself." This raises the possibility that planned outages and other P1 events could be unilaterally excluded from the planning process. Further, it would be difficult for Texas RE to address any inadvertent exclusions or omissions in the planning process under the standard as drafted. Again, this does not appear to be the outcome FERC contemplated in issuing its directive.

Texas RE respectfully requests that the SDT reconsider its approach in light of FERC's directive in Order No. 786 and adopt an approach that broadens the scope of planned outages required to be considered in the planning process. At a minimum, Texas RE suggests that if the SDT wishes to retain the "consultation" model, it should explicitly limit its application to planned outages of less than six months and retain the original bright-line requirements for all other scenarios. Under such an approach, the SDT could revise the existing TPL-001-4 R1.1.2 to read: "Known outage(s) of generation or Transmission Facilities with a duration of at least six months or known outages with a duration of less than six months, as selected in consultation with the RC." Texas RE recommends the SDT further revise TPL-001-4 R 2.1.3 to require that annual Planning Assessments model all P1 contingencies currently in the scope of the existing TPL-001-4 Standard, but again permit those models include planned outages lasting less than six months "as selected in consultation with the RC."

Likes 0	
Dislikes 0	

Response

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	

While the 6 month duration may not be an appropriate requirement, involving the RC is not appropriate either. The responsibility of the RC is “operation” of the system. Any outages in the operating time-frame should have been submitted and reviewed prior to approval. Our expereince in long-term outage planning has shown that it is very unlikely that “planned” transmission outages exist beyond the next six months and that generation outages change weekly. Additionally, to move outages that are expected to last a few weeks to two months into cases that can cover 2-4 months is problematic because as you look at the “most impactful” to include in the base system model, the two or three may not overlap presenting another problem for now selecting what to include. If the Standard stated outages that span the duration of the season being studied that would make this straight forward and remove the RC.

The concept of ***planned outages*** needs to have a footnote or further explanation to clarify that this applies to “planned outages needed to execute the CAP” and be very specific.   Maintenance outages should not be addressed in this standard, thus, verbiage should be added to the standard accordingly. Maintenance outage schedules are typically not definitively known beyond 12 months out, and these would be assessed by Operations Planning closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known.

If the RC remains included, need to add words to allow the RC’s request to include the exclusion of stability studies of known outages that might impact steady state but clearly don’t impact stability. Examples might be areas of the transmission system that are not electrically close to generation and not in areas susceptible to FIDVR

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group would like to clarify an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group would like to state that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also finds the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit.

The SPP Standards Review Group thinks the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, The SPP Standards Review Group have a concern in reference to the number of additional cases and the associated seasons that could be required. The The SPP Standards Review Group would like to suggest proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

Moving away from the 6 month duration outage to limited known outages mixes clearance coordination studies and daily operational studies with planning studies. This creates planning base cases with outages that may or may not happen. Consultation with the Reliability Coordinator (RC) creates added ambiguity for planning studies.

Likes 0	

Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

IID appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 issued on Oct. 17, 2013, Paragraph 40. This standard is applicable only to PCs and TPs per the Applicability section, thus RCs are not under any compliance burden. So what course of actions can the PCs and TPs take to show compliance if they do not receive due cooperation/consultation from the RCs? Please see the comment under #5 below as well. The changes add extra burden on the PCs and TPs for compliance on which they have no control.

Additionally, the outage coordination seems to be more of an Operational Planning issue (for next-day studies up to six months) than a Transmission Planning issue (one to ten years studies). No matter how far ahead PCs and TPs study the system, when it comes to the Operation horizon, the outages need to be studied again with a more realistic system conditions than in the Planning Horizon. Hence any specific analyses performed by PCs and TPs for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon.

Besides, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TPs and PCs have no other allowed mitigation plans, such as operational procedures, except to recommend Corrective Action Plans which result in capital improvement projects. Thus planning for outages in the Near-term Transmission Planning Horizon will only result in capital investment that effect the rates of our customers unnecessarily.

Instead standard **IRO-017 – Outage Coordination** seems to be a much better place to have this directive from Paragraph 40 of Order No. 786 addressed.

Suggestion: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address this in a future revision of IRO-017.

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	

Answer	No
Document Name	
Comment	
It does not make sense to study near-term situation with planning base cases since we would not implement any upgrades. In addition, IRO-017 already contains this requirement.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
The existing language is sufficient to ensure long-term outages are considered in the planning process.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

Requirement 2.1.3 refers to contingency events (specifically P1 events). Section 2.1.4 already requires sensitivity studies associated with the duration and timing of know Transmission outages. Recommend the following wording: "P1 events in Table 1, with known outages modeled as *determined in accordance with* Requirement R1, Part 1.1.2, uner those System peak or Off-Peak conditions."

LCRA TSC supports the changes in 1.1.2 giving flexibility to each region to determine which outages need to be modelled for planning, however, guidance should be provided in the standard not to require that transmission improvements be constructed for transient outage conditions (outages that are due to construction within a single season or of limited duration within a season for instance).

Likes 0	
Dislikes 0	

Response

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	No
Document Name	

Comment

KCP&L does not support the proposed changes to R1, Part 1.1.2.

The proposed TPL-001 revisions removing the six-month planning time period is without consideration of the expressed scope of TPL-001, to model and study system reliability within the Near-Term Transmission Planning Horizon period which the NERC Glossary defines as 1 to 5 years. Also, the revisions seek to address potential conditions that are better addressed within operational assessments, like TOP-002.

We suggest revisions to R1, Part 1.1.2 not be made.

Expanded Scope

We recognize that the revisions reflect Commission directives but that does not relieve or change our TPL-001 expansion of scope concerns. By removing the six-month modeling threshold, R1 potentially requires modeling that will offer little value in support of BES reliability.

Using planning models to consider contingencies for unusual system conditions is without controversy; however, it is not unusual for issues to appear in real-time system operations that have not been identified in Near-Term planning assessments.

Relevant Variables Not Available for Use in Near-Term and Long-Term Studies

Variables used to develop an accurate study are not available for use in a long-term study: temperature, outages, dispatch, and load and transfer levels. Near-Term planning assessments generally assume some uniform ambient conditions for the area to be assessed. For large RTOs such as Southwest Power Pool, ambient conditions can vary widely across the entire RTO. These system conditions are better assessed in the Operational Planning Horizon.

Of course, Near-Term Transmission Planning Horizon (NTTPH) modeling and actual system operational conditions modeling are both useful; however, unless current operating conditions are considered as part of NTTPH modeling, the modeling does little to protect or improve reliability in the real-time operation of the BES.

Planning Assessment Issue

Proposed TPL-001-5 R1 requires TPs and PCs to maintain system models to perform Planning Assessments; R2 requires completing Planning Assessments. The NERC Glossary defines Planning Assessment as, "Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies."

Real-time operational conditions are not "…future Transmission performance…" and fall outside the purview of TPL-001. Removing the six-month timeframe from R1.1.2 potentially expands consideration of real-time operational conditions. Such an expansion, considering real-time operational variability within NTTPHs, is inconsistent with the "future" language element identified in the defined term, Planning Assessment.

Maintenance Outages Less than Six Months Pose Little Risk to Reliability

The proposed revisions seem to overlook the fact that planned maintenance outages of less than six months in duration pose little or no risk to BES reliability since they are considered as part of the TOP-002 Standards which use planning variables not available at the time NTTPH studies are completed. Additionally, many planned outages can be taken at times of opportunity when their impact on system operations is reduced.

Examples in Support of Position

Finally, we offer a couple of examples that further support our position: that the proposed revisions to TPL-001 R1.1.2 are already, and more effectively, addressed by real-time operational studies, using variables not available at the time NTTHP studies are completed.

Example 1

In a long range planning study/assessment there might be an exceedance identified for a maintenance outage. Normally, mitigation of that exceedance takes place during near term/real time operational studies. Maintenance outages are impacted/affected more by real-time operational conditions, not some future set of assumed conditions.

Example 2

In the case of outage caused exceedances; they are temporary and typically resolved using operating guides. Also, a Long-Term Transmission Planning Horizon study or a NTTPH study have little value addressing outage caused exceedances which are better addressed when considered closer to the time of the event, allowing the study to consider conditions likely most similar to those at the time of occurrence.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") disagrees with the proposed changes. CenterPoint Energy recommends replacing the proposed language for Requirement 1, Part 1.1.2 with "Outage(s) of generation or Transmission Facility(ies) with a duration of at least six months in the Near-Term Transmission Planning Horizon." CenterPoint Energy's recommendation is based on the following: • Moving away from the six month duration outage goes beyond the intent the Planning Assessment of NERC Standard TPL-001-4. Planned outages less than six months should be evaluated in the Operations Planning time horizon. • Per NERC Standard IRO-017-1 Outage Coordination, coordination is already required between several applicable entities, including the Reliability Coordinator, Planning Coordinator, and Transmission Planner, before any planned outages are included in the Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No

Document Name	
Comment	
Removing the 6 month duration moves the TPL assessment from the near term planning horizon to the operational planning horizon. Remove “in consultation with their Reliability Coordinators”. This change will deluge the RCs with requests. The decision on what outages to include should rest with the PCs and TPs who may want to consult their RC, but might also want to consult neighboring PCs and TPs as well.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
The revisions to R1.1.2 and R2.1.3 require the individual PCs and TPs to contact the RC to discuss known outages for long term planning purposes. Seminole is concerned that meeting with the individual TPs and PCs for long term planning of outages is not a function of the RC, and that the drafting team should seriously reconsider the additional requirements it is now placing on the RC, especially since planned outages are already coordinated within the Operations Planning horizon. Additionally, Seminole believes that this requirement should be placed within the existing IRO-017 standard if there is a true reliability need for such coordination; TPL-001-5 is not the correct location for this type of coordination. In R1.1.2, if the RC believes an outage should be included in the System Model and the TP and PC do not believe the outage should be included, what is the process for remedying this problem? Do the TP and PC merely have to show that they consulted with the RC, not necessarily that they came to agreement?	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	

Answer	No
Document Name	

Comment

No, there are a few concerns introduced by the proposed modification of part 1.1.2:

· Moving from a firm threshold to consultation creates ambiguity and potential reliability gaps, and is not an effective means to address the FERC concerns expressed in Order 786. when there are no criteria as to how that consultation is to proceed. Further, we do not read FERC's directive on P.40 of Order 786 to mean replacing the 6-month planned outages with other approaches. Rather, we interpret that directive to mean modifying the TPL-001 standard to address the potential impacts of excluding planned outages of less than 6 months in planning assessments.

· Replacing the 6-month threshold with a consultation with the RC has the following potential shortfalls:

a. The TP's/PC's footprint is not necessarily the same as the RC's; there can be several RCs within a TP/PC area, or the other way around. In these cases, who should be consulted and how to reach an agreement if multiple entities are involved? And on what basis should the RC(s) recommend inclusion of certain planned outages?

b. While the draft standard places an obligation on the TP/PC to consult, there is no mirror obligation on the RC to respond. What if the RC does not respond? Is the TP/PC held non-compliant for having no planned outages included in the planning assessment?

c. Two entities may be assessing the same system conditions included the planned outages, but they could come up with quite different assessment results due to different risk tolerances or approaches applied in the assessment. If the TP/PC and the RC, or multiple RCs when more than one is involved, come up with different assessment results, whose results should prevail?

To address the FERC directive without the above potential reliability gaps or shortfalls, we offer the following suggestions:

1. Keep the 6-month planned outage threshold, and supplement it with: Any planned outages that are deemed by the Reliability Coordinator of the concerned facilities to have a reliability impact in the tome frame of the planning assessment being pursued by the Transmission Planner or Planning Coordinator.

2. Add a requirement for the RC to respond to the TP's/PC's request to assess the reliability impacts of planned outages of less than 6 months during the assessment period.

Note: CAISO and ERCOT do not support this comment.

Likes 0	
Dislikes 0	

Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Due to the large number of Planning Coordinators and Transmission Planners in the Reliability Coordinator area, this would be too much of a burden on the RCs to provide appropriate feedback without causing a significant delay or setting the threshhold too low where most if not all planned outages which would significantly increase the time needed to complete the assessment. If the 6 month requirement is removed, the PCs/TPs should provide a reason those planned outages were selected. This would be similar to the language allowing the PCs/TPs to determine which Planning Events are selected to evaluate.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
FMPA appreciates the efforts put forth by the SDT to address the Commission directives from Order No. 754 and Order No. 786. We agree with R1 Part 1.1.2 and subsequently with R2.1.3 (steady state analysis). The concern here is that steady state events refer to coordinating with the RC while stability events do not – the implication being that in stability we must study all known outages as opposed to those which are carefully selected. Also, for 2.4.3, explicitly calling out P1 events from Table 1 effectively removes the ability of the PC and TP to apply engineering judgement to study those events that are expected to produce the most significant impacts, and instead adds “busy work”. Furthermore, the extent of that “busy work” is unclear, since if we are required to run P1 events, how many buses away from the affected area must we simulate these? Few P1 events are simulated in stability studies because P2 events at the same buses are almost always more severe. Please see our comments in the General Comment section below.	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

We disagree with the fundamental premise that there is a reliability need/benefit of studying scheduled transmission outages in the Near-Term Planning Horizon –whether or not they are identified in consultation with the Reliability Coordinator (RC). This is because:

1. scheduled transmission outages almost always qualify as “known” outages only when they are approved/granted by the RC;
2. transition from “prospective” to “known” outages almost always occurs within the operations horizon (0 to 13 months), and
3. very few, if any, transmission outages are approved/granted by the RC well in advance to become “known” outages in the Near-Term Planning Horizon.

Consequently, we assert that deleting Part 1.1.2 from the standard will not have any adverse impact on the planning assessment of future BES reliability.

However, if the SDT is not persuaded to delete Part 1.1.2, we recommend improvements to the verbiage in Part 1.1.2 to address the ambiguity and lack of detail associated with what comprises “consultation with the Reliability Coordinator”.

Further, it is also ounclear why scheduled outages that are “known” would nevertheless have to be “selected” in consultation with the RC – wouldn’t *all* outages that are scheduled/approved by the RC for Year One through year 5 time horizon qualify as “known” outages to be included in the analyses (and hence no selection)?

NERC should provide a clear directive to the RC, where the RC provides a list (in a timely manner to complete the assessment) of know outages to the TP, only after the RC coordinates with the TO for transmission outages and with the GO for generation outages. The TP/PC do not own any assets nor are they aware of predetermined maintenance schedules required by both the TO and GO. Additionally, if TOs, GOs, etc. actively participate as required by MOD-032-1, these known outages would be captured for the respective seasonal time frame.

We suggest the SDT looks at the recommendations in NERC SAMS white-paper on Order 786 for guidance in the case that 1.1.2 is revised.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
Obtaining known outage(s) or Transmission Facility(ies) through the RC for the Near-Term Planning Horizon may be difficult for PCs and TPs, unless the RC has a maintained and approved list of known outages for TPL studies. To sort out applicable outages for the Operations and Planning studies would be a burden for the RC. Additionally, the expectation for the PC/TP to read and extract that information from the RC's maintained and approved list of known outages, is impractical. Therefore, SNPD suggests the Drafting Team remove any language that requires consultation with the RC and we recommend restoring the original language to Requirements 1.1.2 and 2.1.3 and restating "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." If/when the Drafting Team prefers to have a lesser duration than six months, as required by NERC staff, we would support a duration of at least 3 months, for "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least three months."	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The proposed coordination of outages with the RC forces a merging of two disconnected timeframes, and reduces the RC's focus on operational activities. The prescribed 6-month outage duration in the current standard provides a clear separation between the Operations Planning Horizon and the Near-Term Planning Horizon. Furthermore, asking the RC to be directly involved in the near term planning horizon expands on their defined purpose as documented in the NERC Rules of Procedure. It is unclear what types of outages are to be considered under 1.1.2. SRP recommends clarification on what types should be considered e.g. breakers, switches, etc. It is unclear what "consultation" means. If the SDT retains the proposed changes, SRP recommends the SDT clarify what level of coordination is required.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The NSRF recognizes the TPL drafting team is attempting to address a directive from FERC Order 786 in a reasonable and flexible manner. It's the NSRF's understanding that FERC expressed concerns about maintenance outages of equipment that could not be taken out-of-service even at low load levels. The NSRF agrees if there are known or demonstrated important BES generators, lines, transformers, or bus sections that cannot be taken out-of-service even at Off peak load levels, a Corrective Action Plan (CAP) seems apprpriate. The RC or TP could list the known or demonstrated Element on a corrective actions list for the TPL standards similar to PRC-023 and R6. Any newly identified Protection System should have a similar study and implementation period clearly outlined in the standard if possible. There are concerns that Reliability Coordinators do not have (1) an adequate venue for consultation on selecting outages and (2) knowledge of outages with sufficient lead time (36 or 60 months advanced knowledge) to perform the required assessments and implement resulting Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Since RC is now required to supply planned outage information they should become an applicable entity.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
ATC agrees with the proposed change, but is concerned that Reliability Coordinators do not have (1) an adequate venue for consultation on selecting outages and (2) knowledge of outages with sufficient lead time (36 or 60 months advanced knowledge) to perform the required assessments and implement resulting Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
ISO-NE encourages conforming changes to Reliability Standard IRO-017.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	Yes
Document Name	
Comment	

Additional guidance on “consultation” with the RC would be helpful, should this point to IRO-17?. In addition to this the SDT should consider adding the RC to the applicable entities.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	

Answer	No
Document Name	

Comment
1. IRO-017-1 already requires the RC to maintain a coordination process for the Near-Term Transmission Planning Horizon. The proposed approach in TPL provides little guidance to the RC/TP/PC as to what level of detail to model future outages. This may lead to widely varying practices across regions. 2. We support the other approaches suggested by FERC to limit the scope based on both time and outage significance. The proposed alternate for R1.1.2 is: Schedule outage(s) of Generation or Transmission Facility(ies) that are identified by the Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and lasting longer than 90 days. 3. It is important to note the difference between a planned outage in the sense: (1) that maintenance crews "plan" for insulation testing of every transformer every three years, and (2) that a nuclear plant plans to be offline for refueling from exactly 3/3/2019 @ 19:30 to 9/15/2019 08:00. In the former case, the exact outage dates are both unknown and highly flexible, whereas with the latter the outage has specific dates that can be modeled and it must occur regardless of system conditions. The previous 6 month limit served as a screen to identify only those outages which were likely to occur during critical system conditions. Most maintenance is scheduled to avoid system peaks. 4. It unclear how to model planned outages in year one, year three or year four if the TPL planning assessment uses year two and year five.

Likes 0	
Dislikes 0	

Response

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We do not see any reliability gap in the existing standard TPL-001-4 due to the absence of Part 2.4.5. This is because, based on our operating experience, the unavailability of long lead time spare equipment (typically auto-transformer and shunt reactor) has rarely, perhaps never, resulted in unacceptable stability outcome. That is, the risk for instability in BES due to unavailability of spare equipment is minimal, if not negligible. And any BES vulnerabilty to unacceptable stability performance will get adequately assessed when performing stability analyses for P3-P6 Planning Events. Consequently, there is minimal, perhaps even negligible, incremental benefit to be realized by performing additional stability analyses for P1 and P2 events by using prior facility outage as the proxy for unavailability of long lead time equipment failures. Therefore, we do not support the addition of Part 2.4.5 in the draft TPL-001-5 standard.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Similar to the comments entered for question 1 above, explicitly requiring that P1 events be simulated now removes the ability to apply engineering judgment. P1 events would not normally be studied in stability since P2 events at the same buses would produce more severe impacts. In addition, explicitly	

calling out items from Table 1 introduces the ambiguity of how many locations must be studied, since in stability, unlike steady state, it is not feasible to study events at every bus in the system. Please see our comments in the General Comment section below.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
The outage of a piece of equipment with a long lead time should be considered under P6 conditions and not have any additional requirements.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
The word “studied” should be changed to “assessed” or “evaluated” (and the same change should be made in Part 2.1.5.) Overall though, we’re more interested in the change for 2.4.5 since not all equipment that’s part of a spare equipment strategy would require stability simulations (e.g. a reactor), whereas steady state analysis is more commonly applicable	

Note: ERCOT does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
If FERC requires the standard to address spare equipment for dynamics, there should be language that makes it clear that if the non-spared equipment is far away from where the dynamics contingencies are being simulated (i.e. generating stations) then it does not need to be considered. Dynamics contingencies aren't run system-wide like loadflow.	
Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The possible unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES. Suggestion: Requirement 2, Part 2.4.5 is not needed.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Need some verbiage to allow for the exclusion of studies of unavailable equipment that might impact steady state but clearly don't impact stability. Examples might be areas of the transmission system that are not electrically close to generation and not in an area susceptible to FIDVR. An extra sentence "Detailed stability assessments are required only for scenarios where a stability impact could be possible as a result the unavailable equipment" or something simiiar would be appropriate.	
Likes 0	
Dislikes 0	

Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
PG&E agrees with the addition of part 2.4.5, however we believe that more details and clarification on the selection of the transmission equipment, and P1 and P2 contingencies is needed. It is recommended to add language that defines what “major Transmission equipment” would require a stability study. We also offer the the following change to the selection of the P1 and P2 categories from Table 1: “…The studies shall be performed for the P1 and P2 categories identified in Table 1 **[that are expected to produce more severe System impacts on its portion of the BES],** with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.”	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends removing P1 events from Part 2.4.5. The current TPL-001-4 standard already requires entities to evaluate P6 events, which produce the same contingency results that studying P1 events would produce assuming unavailability of long-lead time equipment. It is unnecessary to require the proposed analysis in Part 2.4.5.	
Likes 0	
Dislikes 0	

Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	No
Document Name	
Comment	
NVE is concerned that the scope of this requirement is infeasible. Depending on the amount of spare equipment available, to add dynamic analysis for P1 and P2 events for each unavailable spare, could result in a large number of contingency cases to run. Depending on the number of cases to run, there could be significant resource or run-time issues. As a specific example, it takes approximately 3 weeks for NVE to compute (run) stability analysis on a single model. For 20 pieces of BES equipment without spares, it would push the run-time for all P1 and P2 events to far beyond 1 year, not including time for analysis of the results by staff. NVE recommends allowing the transmission planner to select which P1 and P2 events should be run for each unavailable spare, rather than all P1 and P2 events.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
We recommend replacing the word “studied” with “assessed”. Not all major Transmission equipment that may become unavailable due to an entity’s spare equipment strategy may require stability analysis (e.g. the unavailability of a reactor), and thus studies may not be required in all cases.	
Likes 0	

Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: The unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not necessarily on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES. Recommend removing this requirement.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
The word “studied” should be changed to “assessed” or “evaluated” [and the same change should be made in Part 2.1.5.]	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Steady state analysis per sub-requirement 2.1.5 of the TPL-001-4 standard should be able to capture any thermal or voltage concerns when spare equipment is unavailable due to long lead time. Revising the sub-requirement 2.4.5 to include stability analysis to unavailable equipment due to long lead time potentially adds significant workload without adding any more value than the results of steady state analysis. Suggestion: Retain the existing language in sub-requirement 2.4.5 of the TPL-001-4 standard.	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	
The possible unavailability of long lead time equipment can result in the thermal or voltage planning criteria violations but not on the transient stability of the BES. Hence adding this requirement will burden the PCs and TPs with extra work with no significant improvement in the reliability of BES. **Suggestion**: Requirement 2, Part 2.4.5 is not needed.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Agree with the concept but the word “studied” may have unintended consequences. The words “assessed” or “evaluated” are more appropriate in that devices that do not impact dynamics and therefore may not require a “study” to evaluate the dynamic impact.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA does not see any significant benefit of including the unavailability of long lead time equipment in the dynamic analysis. Potential issues would already be identified sufficiently in dynamics P6 events. If there is an outage of long lead time equipment, operations would mitigate around any potential issues by creating an op guide or utilizing another mitigating measure.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	

Answer	No
Document Name	
Comment	
Order No. 786 does not appear to order, or direct NERC, to change TPL-001 to include stability analysis as part of the spare equipment strategy assessment [see page 58 of Order No. 786]. FERC directed "…NERC to consider a similar spare equipment strategy [as steady state] for stability analysis". SDG&E agrees with NERC's original comments found in Order No. 786 that additional stability assessment will not yield meaningful information and provide a significant reliability benefit. SDG&E recommends removal of section 2.4.5.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Logically, this modification makes sense. However, in practice, this modified requirement is somewhat redundant with Table 1, P3 and P6 events. P3 and P6 events are applicable for stability analysis. The additional study burden may not be commensurate with the expected incremental reliability benefit. For stability analysis covering P3 and P6 events, the initial event (i.e. element or facility outage) is carefully selected to be a impactful outage. In practice, existing study procedures related to P3 and P6 events are a good proxy for the assessment of unavailability of long lead time equipment. We would encourage the SDT to inquire about existing study practices for P3 and P6 events (from the REs and the ISO's) to assess if those existing study practices satisfy the intent of the proposed Req # 2.4.5.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the proposed changes to R2, Part 2.4.5.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group agrees with drafting team adding the new sub-part of Requirement R2 to address the spare equipment issue in the stability assessment. The SPP Standards Review Group would like the regulatory bodies to consider adding language in the Steady-State Assessment area of NERC Standard TPL-001 to address the Stability Assessment of the spare equipment strategy. This would mean that if a spare equipment strategy caused issues in the Steady State Assessment, it would prompt the Transmission Planner (TP) and Planning Coordinator (PC) to perform additional Stability Assessments for those specific issues.	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Requirement R2.4.5 specifies that studies be performed for the P1 and P2 categories; whereas, Requirement R4 specifies that R2, Parts 2.4 and 2.5, be performed based on the Contingency analyses listed in Table 1. To improve clarity, LES recommends rewording R4 as follows: R4. “For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons as described in Requirement R2, Parts 2.4 and 2.5.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports the idea behind the requirement, as it could flag important reliability issues that operations planners need to be aware of.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	

Answer	Yes
Document Name	
Comment	
We recommend replacing the word “studied” with “assessed”. Not all Transmission equipment that may become unavailable due to an entity’s spare equipment strategy may require stability analysis (e.g. the unavailability of a reactor), and thus studies may not be required in all cases.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
System adjustments would be required following the outage of the equipment with long lead times. Such adjustments should include generation redispatch to address both steady-state and stability concerns. Reviewing system stability issues including system adjustments following the long-term outage of critical system equipment is a reasonable enhancement.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes
Document Name	

Comment	
PGE agrees that the dynamics analysis include spare equipment with long lead times. The requirement will add a limited number of additional cases to be studied. This will increase the time required to complete the dynamics analysis, and therefore increase costs to PGE to demonstrate compliance with this standard.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Corn Belt agrees, but suggests that "more than 1 year" be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity. Concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
The NSRF agrees, but suggests that “more than 1 year” be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity. The NSRF has concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
While the revised footnote is an improvement, clarifications are still needed to properly identify the redundancy requirements. We believe that minimum design requirements should be included in the standard. That will allow the Planning Coordinators/Transmission Planners to have a consistent interpretation of the footnote 13. The following questions demonstrate the ambiguity around redundancy: - Is it allowed to have two control circuitries that use different wires but share the same control cable? - Do the trip coils need to be monitored? There are situations when non BES elements are connected to BES buses (e.g. radial circuits supplying loads). The standard must clarify which protection systems failures needs to be studied since an uncleared close in fault on a non BES element connected to a BES bus has the same consequence as an uncleared close in fault on a BES element. Do the protection systems installed on non BES elements connected to BES buses and protecting portions of the BES buses need to meet redundancy criteria?	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	

Answer	No
Document Name	

Comment

General recommendation: Footnote 13 should be carefully reviewed and modified (or expanded), as necessary, to be consistent with the Rationale for the modified P5 event, and also consistent with the NERC Glossary definition of “Protection System”. Enough detail should be provided in the footnote to ensure clarity of what needs to be considered.

Footnote 13.1 mentions “A single protective relay”. As written, this does not provide sufficient detail for the planner or protection engineer to focus on. The term protective relay needs to be clarified. For example, could this include auxiliary relays such as lock-out relays that are used for tripping (function 86)? Alternatively, does this non-capitalized term only apply to relays that operate on or respond to measured electrical quantities such as current and voltage? Additional clarification is required to allow the planner / protection engineer to be completely focused on what is required for compliance.

The rationale mentions that the scope of consideration should be limited “to those relays that are used for primary protection at the local terminal…”. What is meant by “primary protection”?

Footnote 13.4 needs clarification. For example:

- Does 13.4 mean that redundant relays tripping through a single wire to a single trip coil would constitute a non-redundant component of a Protection System?

- Does 13.4 mean that redundant relays tripping through a single trip coil would constitute a non-redundant component of a Protection System?

Considering the complexities of 13.4, sample, or representative protection system diagrams that would constitute examples of non-redundant components of a Protection System would be helpful. Such diagram(s) would provide clarity in a similar fashion as the diagrams provided in the NERC BES Reference Document.

A general concern here is that this modified footnote, as written, is very confusing. The confusion imposed, along with the additional study burden, may not be commensurate with the expected incremental reliability benefit.

Finally, we would note for consideration, that failure of a non-redundant component of a Protection System could result in not only increased total fault clearing time, but also an increase in the number of elements that must be tripped to clear the fault. It is recommended that the Rationale section be modified to mention this additional reliability implication.

Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	

We disagree with the inclusion of the communication system component to Table 1 footnote 13. A single point of failure in a communication system component poses a lower risk for delayed clearing for a variety of reasons and should not be included in footnote 13 as stated by the NERC SPCS/SAMS Order 754 report. Analyzing these risks in planning studies provides significant additional burden for limited gain in reliability.

We understand the SDT's reasoning but urge them to reconsider as this will add a whole new level of detailed analysis by the entities which will lead to a lot of questions requiring guidance from the SDT to ensure consistent application continent-wide.

Basis for our position

To effectively analyze a single point of failure (SPOF) in communication systems the protection schemes used to protect the element and operation of these schemes need to be considered. Looking merely at common hardware, common circuitry and a common communication path is not enough to determine if a single point of failure exists. For example a common communication path can be used for both System A protection via a Directional Comparison Blocking Scheme (DCB) and System B protection via Line Current Differential. If the common communication path fails and a fault then occurs, the DCB scheme will trip with no intentional delay and clear the fault (proper communication system function is not needed). DCB misoperation (overtrip) is associated with faults outside the zone of protection and thus is not associated with delayed clearing as specified in Table 1. Eversource would contend that this is not a single point of failure. Does the Drafting team and the rest of NERC agree?

If communication systems are to be included in footnote 13, considerable additional guidance will need to be included in the standard to ensure only the correct consistent application of SPOF continent-wide. The proposed footnote 13.2 states "A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported."

{C}·   What does "not monitored or not reported" mean? If an entity performs a manual carrier check-back test once every 4 months, which is allowed for unmonitored protections system communication system component maintenance per PRC-005, is that considered monitoring or is that "reporting" for the purposes of this standard? Most carrier systems utilize automatic check-back functionality in which case the communication path and end enquipment is checked once a day. Is that frequent enough to be considered "monitored"? PRC-005 uses the following definition for a monitored communication system: "Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function". Alarming criteria in PRC-005 is specified as : "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated."

{C}·	Is having System A and System B protection communication paths share a common structure a single point of failure, such as a common microwave tower? NPCC Directory 4 does not count this as a recognized single point of failure.

{C}·	Is having System A and System B protection communication paths utilize third party leased communication path a common point of failure even if the third party claims they are diverse (two leased phone lines). NPCC Directory 4 would discourage this and claim that it is not an effective diverse path.

We agree that today, most entities do enable continuous or periodic automated testing of their communications system components and do alarm them to a 24/7 montiored control center where action can be taken. Therefore, we feel the effort to correctly defined and identify the small number of unmonitored communication systems that correctly meet the SDT intent, as it applies to delayed fault clearing, is overly burdensome relative to the reliability benefits.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

No. The NSRF recommends that “Cascading” be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term “Cascading” remains too vague and subject to change. A MW threshold is a better “bright line” criteria.

The NSRF recommends each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

The NSRF asks if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design (meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

The NSRF asks if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754report identified communications systems posed a lower risk level.

Example NERC Defined Protection System Component Classes, Scope and Applicability:

NERC Bulk Electric System (BES) protective relays/sudden pressure relays/reclosing relays:

NERC BES PRC-005-6 Protection System electromechanical primary and auxillary relays are included in footnote 13. This includes PRC-005-6 identified sudden pressure and reclosing relays.

NERC BES associated communication systems:

NERC BES PRC-005-6 associated communication systems are included in footnote 13.

Redundant communications system for footnote 13 would be two communications channels. Redundant communications for Footnote 13 does not require separate and diversely routed communications towers.

NERC BES Voltage and current sensing devices:

NERC BES PRC-005-6 voltage and current sensing devices are not included in footnote 13. The SPCS/SAMS Order 754 report identified that voltage and current sensing devices were robust and posed a lower risk level.

NERC BES Station batteries:

NERC BES PRC-005-6 Station batteries are included in footnote 13 with the following exceptions. A single station DC supply is allowed if monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES Battery Chargers:

NERC BES PRC-005-6 station battery chargers are included in footnote 13. A single station charger is allowed if the battery bank is monitored for low voltage and open circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:

NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5

Answer	No
Document Name	
Comment	
Steady-state and stability software cannot not model directly the non-redundant components listed in footnote 13. Instead, the transmission planning engineer must simulate a component failure by deciding how the protection system will respond to the failure (which circuit breakers open and which don't) to clear the fault. Therefore, the engineer, not the software, will determine how the failure is simulated. For the purposes of the standard, the engineer may limit the Category P5 protection failures to those components found in footnote 13 and ignore any other possible single component failure. SDG&E recommends removal of footnote 13 and simplification of the P5 language to read, "Multiple Contingency (Fault followed by a protection failure resulting in multiple elements removed from service)". This would require that a fault followed by a protection system failure be assessed without consideration of protection system redundancy. If an issue is found, then the existing protection system would be reviewed for redundancy. If no redundancy exists, then addition of a redundant protection system can be part of the Corrective Action Plan. SDG&E recognizes that some TPs and PCs may object to doing protection failure simulations of fully redundant systems, but additional simulations can only improve system reliability.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
While AEP does not object to the concept itself of adding "communication system" to footnote 13, we believe its inclusion goes beyond the scope of the current SAR. We believe such an inclusion should not be considered until the SAR has been appropriately revised, and industry afforded opportunity to provide comment on the suggested change. AEP requests additional clarification of footnote 13.4 regarding the phrase "through the trip coil(s) of the circuit breakers or other interrupting devices." In the data request associated with FERC Order 754 (Single Point of Failure on Protection Systems), local breaker failure protection was allowed to be modeled in cases of non-redundant trip coils. AEP recommends either changing the proposed text to allow the consideration of local breaker failure protection for trip coil failure (which has already been studied in P4), or instead, the elimination of the phrase altogether.	

Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No
Document Name	
Comment	

While we agree with the clarification of components of a Protection System, we would like to see further clarification under P5 and the new Extreme Events (2e through 2h) as to where the fault and the failure of the components of a Protection System occur.

Is the intent of these new faults to have the fault and the failure of the component of the Protection System locally, remotely, or both?

Can this be added ("**local** failure of a non-redundant component of a Protection System", or "**remote** failure of a non-redundant component of a Protection System", or "**local and remote** failure (not simultaneously) of a non-redundant component of a Protection System") to the P5 and Extreme Events?

A fault locally along with a local failure of a component of a Protection System would be similar to NPCC's Criteria A-10 test, however, a fault locally with a remote failure of a component of a Protection System would be a scenario new to the industry, possibly leading many entities to discover scenarios where they have uncleared faults, however this may not be apparent to entities to be studied unless it's clarified in the standard.

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	

1) Clarity needs to be added to “single relay” to exclude instances where a second relay performing a different function is also installed.

2) Clarity needs to be added to “single communication system” to specify the devices that need to clear a fault as opposed to devices that may result in overtrip.

3) Clarity should be added to allow for redundancy provided by devices responding to non-electrical quantities.

4) Clarity should be added for what constitutes “not monitored” or “not reported” in the instances of communication system and DC supply.

5) Clarity that redundant trip coils are not required.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1,3,5,6

Answer	No
Document Name	

Comment

The SPCS report on single point of failure did not include “a single communications system, necessary for correct operation of protective functions, which is not monitored or not reported”. The SPCS concluded that analysis of communications systems with regard to single points of failure did not pose enough of a risk to warrant addition in footnote 13. This assessment was based on SPCS efforts over the years studying blackouts/significant events and their causes. Communication system failures were not a causal factor in the significant events studied by the SPCS. Failures of relays and auxiliary relays have been causal in significant events. Thus, we agree with the SPCS assessment. We do agree with the drafting team that the vast majority of communications systems are monitored 24/7 to a central location. The few unmonitored systems on our system are applied at HV voltage levels where consequences of slow clearing are much less significant. PRC-005 already requires that unmonitored communications systems be tested on a frequent basis. In our case and likely for many others, this is sufficient motivation to create a program to add monitoring to unmonitored communications systems. All of these items relegate the addition of communication systems to footnote 13 to an exercise in documenting the low number of communications systems that are unmonitored. This addition then becomes purely burden with very little if any affect on our goal of providing an adequate level of reliability for the power system. Thus we recommend removing communication systems from footnote 13 in the revised standard.

Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

Recommend that "Cascading" be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term "Cascading" remains too vague and subject to change. A MW threshold is a better "bright line" criteria.

Recommend each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

Ask if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design

(meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

Ask if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754 report identified communications systems posed a lower risk level.

Example NERC Defined Protection System Component Classes, Scope and Applicability:

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NERC BES associated communication systems:

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Redundant communications system for footnote 13 would be two communications channels. Redundant communications for Footnote 13 does not require separate and diversely routed communications towers.

NERC BES Voltage and current sensing devices:

NERC BES PRC-005-6 voltage and current sensing devices are not included in footnote 13. The SPCS/SAMS Order 754 report identified that voltage and current sensing devices were robust and posed a lower risk level.

NERC BES Station batteries:

NERC BES PRC-005-6 Station batteries are included in footnote 13 with the following exceptions. A single station DC supply is allowed if monitored for low voltage and open

circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES Battery Chargers:

NERC BES PRC-005-6 station battery chargers are included in footnote 13. A single station charger is allowed if the battery bank is monitored for low voltage and open circuit

alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:

NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

WAPA agrees with the intent but offers improvements to the language.

In Order No. 786 (P69), FERC declined to direct that NERC revise this standard to apply to all protection system components, at least until NERC completed its analysis of the Order No. 754 data responses. After review of that data, the NERC SPCS and SAMS recommended including protective relays, DC control circuitry, and station DC supply in the standard. This recommendation was based on the survey results regarding the prevalence of non-redundant protective equipment and the simulated disturbance magnitude of a failure of non-redundant equipment. The SPCS and SAMS report, did not, however, quantify the likelihood of each type of non-redundant protection component failure. Thus, it is hard to fully agree with the SPCS/SAMS recommendations at this time (and the Standard Authorization Request is only to “consider” them rather than “address” them).

WAPA does not believe that it is necessary to include analysis of all of these non-redundant Protection System component failures in the TPL standards at this time. Alternatively, if they are included, then they should be treated similarly to the current treatment of Extreme Events where there are no strict performance requirements or mandates to create Corrective Action Plans. In fact, the SPCS and SAMS report suggested that auxiliary relay and lockout relay failures were the main culprit in previous disturbances but failures of other equipment are generally rare or unimpactful (p.7). If anything, the P5 category expansion should be limited to auxiliary and lockout relays. This would allow utilities to focus their money and attention to mitigating the most severe potential impacts rather than building redundancy into systems where it will most likely never be needed.

WAPA recently studied the cost of eliminating single points of failure at a typical older substion. WAPA estimates that building full redundancy will likely cost over $1.3 million and take about a year and a half to implement. The main reason why it takes this long is due to scheduling outages. During outage timeframes, WAPA may have to curtail transmission or generation schedules, which many WAPA customers and staff would view as a decrement to reliable operations. The commissioning of new relays also requires significant testing, which conceivably puts WAPA at greater risk for human error. Furthermore, WAPA does not have any record of a P5 or EE2d type of event in the last 50+ years. Just building redundancy into substations will be a challenge to explain to WAPA ratepayers, and it may prove extremely difficult if WAPA is required to add costs and time for DC control circuitry equipment. Instead, WAPA may desire to focus its limited resources on developing replacement plans for aging equipment (e.g. transformers) or improving security measures.

As a reference, here is the language from SAMS Table 1.3. *DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC distributionpanel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).*

In addition to the concerns mentioned above, WAPA suggestions the following clarification of components of a protection system (Footnote 13).

Suggested Language:

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 used for primary protection;

2. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported;

3. A single DC supply associated with protective functions that is not monitored for both low voltage and open circuit, with alarms centrally monitored;

4. A single DC Control Circuitry that causes the primary and local backup protection system to not operate properly and triggers remote delayed clearing.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1

Answer	No
Document Name	

Comment

PGE does not agree with the inclusion of Footnote 13.3 *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.* It is PGE's interpretation that this requirement is intended to address the potential failure of a

station battery when called upon to operate. The language in the footnote does not address monitoring the health of the battery, but instead addresses monitoring the battery charger. Monitoring voltage of a battery is really monitoring the operation of the battery charger. A functioning battery charger can mask a failed battery. Discharge testing of a battery is the only known reliable way to assess the batteries health. PGE does not agree with the inclusion of Footnote 13.4 *A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.* Table 1 requires that breaker failure be studied under Category P4. It is unclear how this footnote will add benefits and clarity to the TPL standard.	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The further clarification is useful for the most part with one exception. SCE proposes that footnote 13, part 4 include an exclusion for single control circuitry with monitoring as done for parts 2 and 3. Currently the PRC-005-6 supplemental reference allows for maintenance programs to use both traditional time-based maintenance (minimum periodic intervals) and condition-based maintenance (continuously monitoring for inoperable components) to pre-emptively identify protection system issues and satisfy FERC's protection system verification directives from Order 693. SCE believes that trip coil/control circuitry monitoring should not only adequately mitigate any reliability risk that footnote 13, part 4 tries to capture, but can also be used in Corrective Action Plans where single control circuitry is not monitored and assessments demonstrate an impact to reliability. SCE recommends the following language for footnote 13, part 4: 4. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices, which is not monitored.	
Likes 0	

Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
The clarity afforded by the device type was helpful in conducting inquires. AZPS suggests retaining the following sentence in Table 1, #13 regarding the type of relays the standard applies to: "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)."	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
IEEE recommended practices are used in designing typical generator protection schemes. Prevailing protection schemes (based on IEEE Standards) for a majority of generators that are in service may not have completely redundant protection schemes as clarified by proposed footnote 13. It may not be practical for GO/GOP to implement a completely redundant protection scheme. For example, it may not be physically possible to install additional CTs on the generators or redundant battery systems. The Standard Drafting Team should develop an application guideline with appropriate figures to clarify the Standard Drafting Team's goal with this clarification. Refer to Figure 1.1 of NERC Technical	

Reference Document , “Power Plant and Transmission System Protection Coordination (http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf)	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
For P5, the probability of the occurrences of these component failures do not warrant a planning event. NIPSCO believes the current set of Planning events encompass the most likely to occur protection component failures, therefore P5 should remain as is. NIPSCO believes the addition of these components, specifically the single dc supply, will involve most BES facilities. This will create more extreme type contingencies involving loss of a complete substation. With most BES substations not having redundant protection components as the proposed footnote lists, the mitigations will result in unreasonable costs that were not intended by the standards or FERC Order 754. If these components are to be considered, it should remain as an extreme event.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

The defined components of the Protection system seemed to have made the intent and clarification unclear. While the footnotes add clarity to what single points of failure exist on protection systems, losing the language describing which types of relay are covered reduces clarity.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

Footnote 13 requires some changes. First of all, the P5 contingency event description clearly indicates that the P5 contingency only covers situations where there is “Delayed Fault Clearing due to the failure of a non-redundant component of a protection system to operate as designed”. Therefore, it should be clarified in footnote 13 that any single component failure that results in overtripping , but not delayed fault clearing, should not be considered in the P5 contingency. For example, this would eliminate a single communications channel failure in a directional comparison blocking scheme (very common scheme for transmission line protection) from being considered a single-point of failure since this failure would result in overtripping, but not delayed fault clearing. However, a single channel communications failure for a permissive overreaching transfer trip scheme would be considered a single component failure since such a failure could result in delayed fault clearing.

Second, there is no mention of instrument transformer failure as a single component failure, but such failures could directly result in a failure to trip and thus subsequent reliance on delayed remote backup protection to clear the fault. A NERC technical paper titled “Protection System Reliability – Redundancy of Protection System Elements”, which was prepared by the NERC System Protection and Control Task Force and dated November 18, 2008, correctly indicates that instrument transformers can represent a single point of failure in a protection system as follows:

From Section 5.1 of the technical paper: “At least two isolated and separate AC current sources (referred to as CT inputs) for Protection Systems are required to meet the proposed requirement for CT redundancy. Figure 5-3 shows a common arrangement that addresses the current measurement redundancy requirement. CTs are required to provide totally separate secondary AC current sources for each redundant Protection System. This is required so that a shorted, open, or otherwise failed CT circuit will not remove all protection elements requiring current.”

From Section 5.2 of the technical paper: "At least two separate secondary windings supplying voltages for Protection Systems are required to meet the proposed requirement for AC voltage source redundancy when such voltage sources are required to satisfy the BES performance required in the TPL standards. This is required so that a shorted, open, or otherwise failed voltage circuit will not remove all protection elements requiring voltage."

The proposed requirements outlined in the NERC technical paper align well with how most transmission owners have historically developed fully redundant protection schemes, and thus should be incorporated into Footnote 13 of the proposed TPL-001-5 standard.

Footnote 13 should clarify that a single protective relay means a single protective relay unit and not a single protective relay element. For example, a digital relay with multiple elements could experience a power supply failure, thus removing the functionality of all elements included in the relay unit. Therefore, using two relay elements in a single protective relay unit would not provide single-point-of-failure redundancy.

Footnote 13 should clarify that DC control circuitry specifically includes auxiliary relays and lockout relays, since such relays have often been the cause of single-point-of-failure events in the past. Furthermore, footnote 13 should clarify that only those DC control circuitry failures that do not result in merely a breaker failure operation should be checked. For example, if a circuit breaker includes only a single trip coil, but the DC circuitry that energizes the trip coil from redundant protective relays is isolated from the DC circuitry that initiates breaker failure from the same redundant protective relays via different output contacts, then a single trip coil is clearly part of the breaker and not part of the protection system since a failure of the trip coil results only in a P4 stuck breaker contingency (i.e., it would not cause a failure to initiate breaker failure, only a failure of the breaker to trip).

Also, the SDT may want to consider clarifying in Footnote 13 that only DC control circuitry associated with tripping circuit breakers should be considered when assessing whether or not there are single points of failure. That is, DC control circuitry required to close the circuit breaker would not cause delayed fault clearing through failure to trip, and should be excluded from the list in footnote 13.

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	

The parenthetical that specifies the different relay types should not be deleted because the term “single protective relay” is not specific enough. Also, the definition of the word “reported” included in the Rationale box should be moved to the footnote to make clear what “reported” means in numeral 3. As proposed, these sentences should read: 2. A single communications system, necessary for correct operation of protective functions, which is not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated. 3. A single dc supply associated with protective functions, and that single station dc supply is not reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated for both low voltage and open circuit.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees that additional footnote regarding further clarification of relay to components of a Protection System is helpful, but would request the drafting team to further clarify note 13 subpart 1 that the Transmission Planner include in the analysis only those single relays that are associated with isolation of fault. PacifiCorp believes that the note should be written as **“1. A single protective relay used for isolation of fault “** Similar to comment above, note 13 subpart 2 should also clarify that communication required to isolate a fault should be redundant or monitored and reported. Also clarification as to what monitoring and reporting for the single communication systems should be performed to eliminate that as part of non-redundant protection system component would be helpful.	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
We appreciate the attempt to further clarify the non-redundant components of a Protection System. However, from a planning perspective, it makes no difference as to why or what portion of the Protection System failed to operate and results in the delayed clearing. We are typically more interested in the most severe fault with the longest clearing time or the longest time delay. This change, if adopted, will likely require a change in our philosophy of running the most severe contingencies for each of the major substations, to running all contingencies to identify possible violations. This change as proposed will require a significant increase in stability analysis, and for very little benefit.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
If the drafting team decided that the listed four items in Footnote 13 define single points of failure of Protection Systems, Hydro One suggests revised language in order to provide clarity for both the Planners as well as the P&C SMEs who will be called upon to evaluate the Protection Systems. We suggest the wording in the standard be clarified either directly or through appropriate descriptions in the rationale boxes. We also note that the 4 items in the footnote seem to be a mix of truly redundant components or singular components whose health is monitored. True Protection System redundancy to avoid single point of failure does not depend solely on health monitoring to meet redundancy requirements. We note and reference a previous work by the NERC SPCS concerning protection system redundancy entitled Protection System Reliability – Redundancy of Protection System Elements" (November 2008) where much of the wording in Footnote 13 and the corresponding rationale was derived from.	

Please consider the following comments and suggestions:

1. Table 1 Footnote 13.2 – (Also, reference Section 5.4 of NERC SPCS report)

Please clarify if the intent that a single monitored communication system necessary for correct operation of protection functions means that a single communication channel which is monitored meets the redundancy requirement. Quoting from the NERC SPCS report identifying redundant teleprotection schemes:

Some acceptable communication schemes are:

• Two power line carrier systems coupled to multiple phases of the line.

• Two microwave systems and paths with multiple antennas on a common tower.

• Two fiber paths between terminals (two fibers in the same cable are not acceptable)

• Two separate communication systems of different technologies and equipment (e.g., fiber

optic and digital microwave).

It would appear from the draft wording for this footnote that any singular communication channel, as long as it is monitored, does not need to be considered in the planning assessment. Please provide clarity on this through revised wording or in the rationale box. We believe that a communication channel is a component of the communication system. Unless this is clear, it may lead to confusion during the necessary Protection System assessments.

2. Table 1 Footnote 13.3 – (Also, reference Section 5.8 of the NERC SPCS report) – we have two concerns with this footnote where a single DC system which "is not monitored or not reported for low voltage and open circuit is considered non-redundant." Firstly, it should be noted that in a single DC battery system, the RTU will likely also lose DC supply meaning a loss of DC supply alarm could not annunciate that specific condition to a control centre directly. Secondly, the use of the term "open circuit" is too broad. An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. We believe the intent of this footnote is to capture only the opening of the main protective device (breaker/fuse) after the DC system. In light of these 2 issues, we would like to suggest the following wording change to address these concerns:

13.3 A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, either directly or indirectly, for both low voltage and for interruption of the station DC supply by the main protective device." We believe this wording along with appropriate rationale would help clarify this footnote.

3. Table 1 Footnote 13.4 - (Also, reference Section 5.5, Section 5.6, and Section 5.7 of the NERC SPCS report) - If the drafting team considers monitoring for commumication system and DC supply to satisfy redundant requirements, then why can't trip coil monitoring be considered as well?	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	

Item #1 states a single relay, not a single protection package. Is our interpretation for item #1 that a package of (electromechanical) component relays (i.e. three relays in the single package) is redundant in accordance with TPL-001-5 correct? Since, within the sensitivity of the devices, a set of 3 phase and 1 ground relay detects any of the classic fault types (3PH, Ph-Ph, DLG, and SLG) with at least two (2) relays. We would like to provide an example with a transmission line that does not have two directional ground relays, but one directional distance relay (KD relay) per phase and one directional distance ground relay (IRD relay) for the SDT's review. With a single line to ground fault and the directional distance ground relay fails, the instant overcurrent relay will operate, but at a potentially different (e.g., slower) speed (depending on the fault current magnitude). In accordance with footnote 13, should the directional distance ground relay and the overcurrent relay be considered redundant, and hence not constitute a single point of failure per TPL-001-5? If the relays in the example are considered redundant, could we assume either relay to operate and hence do not need to consider them non-redundant components of a Protection System per footnote 13? Alternatively, if the relays in the example are considered non-redundant, do we need to test for operation of either of the two relays (i.e. both) per footnote 13?

Item #2 does not specifically state anything about the speed of protection, although the associated rationale statement states that the evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Is our interpretation for item #2 that one high speed and one step distance will provide a correct operation, so it doesn't need to be tested under footnote 13? Is our interpretation for item #2 that while a single communication system applied over a single communication medium which is not monitored or not reported constitutes a non-redundant component of a Protection System, a monitored pilot channels, such as FSK, is to be considered a redundant communication system in accordance with footnote 13? Further, is our interpretation for item #2 that this extends to on-off carrier channels with check-back testing so that only those without check-back reporting are considered non-redundant in accordance with footnote 13?

It appears that the addition of “A single communications system, necessary for the correct operation of protective functions, which is not monitored or not reported” is beyond the scope of the SAR and the SPCS and SAMS recommendations in response to FERC Order No. 754. Please consider if this addition to footnote 13 is necessary.

Is our interpretation for item #3 that it is sufficient to monitor the battery and alarm if it is getting low correct in accordance with footnote 13? In other words, are we required to evaluate the failure of the battery, or is it sufficient to monitor for low battery voltage, while not knowing when it actually fails?

Could the SDT please provide further guidance in form of clarifying language or application guidance as related to item #4 in footnote 13? Is our interpretation related to item #4 that redundant relays tripping through a single wire to a single trip coil would constitute a non-redundant component of a Protection System? While item #4 does not seem to require dual trip coils, it seems to require dual wires. Does the last sentence provide a correct interpretation of a single control circuitry associated with protective functions through the trip coils of the circuit breakers or other interrupting devices per footnote 13?

Reference footnote 13, bullet 4: We recommend to replace the word “through” with “up to” to make the requirement clearer and less prone to different interpretations.

If the drafting team decided that the listed four items in Footnote 13 define single points of failure of Protection Systems, NPCC suggests revised language in order to provide clarity for both the Planners as well as the P&C SMEs who will be called upon to evaluate the Protection Systems. We suggest the wording in the standard be clarified either directly or through appropriate descriptions in the rationale boxes. We also note that the 4 items in the footnote seem to be a mix of truly redundant components or singular components whose health is monitored. True Protection System redundancy to avoid single point of failure does not depend solely on health monitoring to meet redundancy requirements. We note and reference a previous work by the NERC SPCS concerning protection system redundancy entitled Protection System Reliability – Redundancy of Protection System Elements” (November 2008) where much of the wording in Footnote 13 and the corresponding rationale was derived from.

Please consider the following comments and suggestions:

1. Table 1 Footnote 13.2 – (Also, reference Section 5.4 of NERC SPCS report) – Please clarify if the intent that a single monitored communication system necessary for correct operation of protection functions means that a single communication *channel* which is monitored meets the redundancy requirement. Quoting from the NERC SPCS report identifying redundant tele protection schemes:

Some acceptable communication schemes are:

• Two power line carrier systems coupled to multiple phases of the line.

• Two microwave systems and paths with multiple antennas on a common tower.

• Two fiber paths between terminals (two fibers in the same cable are not acceptable)

• Two separate communication systems of different technologies and equipment (e.g., fiber optic and digital microwave).

It would appear from the draft wording for this footnote that any singular communication channel, as long as it is monitored, does not need to be considered in the planning assessment. Please provide clarity on this through revised wording or in the rationale box. We believe that a communication channel is a component of the communication system. Unless this is clear, it may lead to confusion during the necessary Protection System assessments.

2. Table 1 Footnote 13.3 – (Also, reference Section 5.8 of the NERC SPCS report) – NPCC has two concerns with this footnote where a single DC system which "is not monitored or not reported for low voltage and open circuit is considered non-redundant." Firstly, it should be noted that in a single DC battery system, the RTU will likely also lose DC supply meaning a loss of DC supply alarm could not annunciate that specific condition to a control center directly. Secondly, the use of the term "open circuit" is too broad. An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. We believe the intent of this footnote is to capture only the opening of the main protective device (breaker/fuse) after the DC system. In light of these 2 issues, we would like to suggest the following wording change to address these concerns:

"13.3 A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, *either directly or indirectly*, for both low voltage and *for interruption of the station DC supply by the main protective device."* We believe this wording along with appropriate rationale would help clarify this footnote.

3.Table 1 Footnote 13.4 - (Also, reference Section 5.5, Section 5.6, and Section 5.7 of the NERC SPCS report) - If the drafting team considers monitoring for communication system and DC supply to satisfy redundant requirements, then why can't trip coil monitoring be considered as well?

We would like to see further clarification under P5 and the new Extreme Events (2e through 2h) as to where the fault and the failure of the components of a Protection System occur. Is the intent of these new faults to have the fault and the failure of the component of the Protection System locally, remotely, or both?

Can this be added ("local failure of a non-redundant component of a Protection System", or "remote failure of a non-redundant component of a Protection System", or "local and remote failure (not simultaneously) of a non-redundant component of a Protection System") to the P5 and Extreme Events?

A fault locally along with a local failure of a component of a Protection System would be similar to NPCC's Criteria A-10 test, however, a fault locally with a remote failure of a component of a Protection System would be a scenario new to the industry, possibly leading many entities to discover scenarios where they have un-cleared faults, however this may not be apparent to entities to be studied unless it's clarified in the standard.

Likes 1	Chantal Mazza, N/A, Mazza Chantal
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	No
Document Name	
Comment	

Clarification on communication-aided schemes is needed. The rational states that communication failures do need to be considered in the SPF analysis. Often, and general good utility practice is to provide separate communication paths for critical protection systems, such as redundant fiber on separate routes, fiber and microwave, diverse frequencies on the same microwave path, PLC on separate phases of a line, OPGW and PLC on a line, etc.   Other, less redundant communication configurations are also possible such as multiple individual channels in the same fiber or microwave frequency and path or two OPGW cables on the same structure.

- Is a communication configuration that uses this lower level of redundancy acceptable under the revised P5 and footnote 13?
- Would monitoring and reporting failures of such “less or non redundant” communication facilities make them acceptable?
- How about communication facilities that carry signals for RAS or other controls whose action may not be dependant on the physical telecommunication path?

If the answers to any of these questions are “yes,” that would seem to contradict the SPCS white paper from 2009, which included several examples, in the discussion on communication redundancy.   It may also provide a lower standard for communication compliance than for protective relay compliance. This would not appear to be a desirable reliability result.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy recommends the SDT consider that "*Non-redundant component*" be clarified to refer to "fault clearing initiating devices" leaving the wiring to the discretion of the results of the studies. (relays, carrier, battery, etc.) Duke Energy has concerns regarding the lack of information on what level of redundancy will be required. Based on the rationale provided, it appears that redundancy will not be required where cascading (result of a study) is not a concern, however, more clarity is needed regarding what redundancy would look like as it pertains to this standard. Where redundancy is required does this mean putting in a complete second system to meet compliance for item 4? *"4. A single control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices"?* Does separate circuits, mean separate in same panel or separate in separate panels. Does it mean separate cables in same conduit or separate cable in separate conduit, or could it mean separate conductor in same cable. Regarding redundancy of control circuits, does redundancy mean that separate trip coils are required in the breaker? More clarity is needed on this aspect to fully understand what compliance will look like. Also, regarding #2 in Footnote 13, where it says *"single communication system",* does this mean separate pairs in same cable, or does it mean fiber pair from two cables in two different paths? More clarity is needed on what the SDT's intent is for this language.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
PG&E agrees that adding the components of a protection system to study provides clarity but the impact of this study is not known and more information is needed. The work required to respnd to the FERC ORDER 754 data request was significant and PG&E believes that this change may result in unduly burdensome activities without knowing what the full scope of non-redundant facilities are. Furthermore PG&E believes that the Transmission Owner may need to be added as an applicable entity to identify the facilities which do not meet the redundancy criteria specified here and assist in identifying the resulting outages and clearing times.	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group suggests that on the rationale on page 23 of 33, there seems to be rationale missing, supporting communication- aided components of a protection system. The SPP Standards Review Group suggests that in footnote 13, clarify that this is a finite list, and add some punctuation to define the list. Additionally, clarify Statement 4, and provide an explanation. The SPP Standards Review Group suggests this would be more appropriately addressed in a PRC standard due to the protection scheme issues. The SPP Standards Review Group suggests that the drafting team add clarity to the guidance document to address Directional Comparison Blocking (DCB) protection and whether or not it meets the intent of redundancy and what is meant by monitoring the communication system.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	

The potential cost of this to improve our system would be phenomenal. Even though it is only limited to 3-phase faults, this would produce additional burden to the annual planning assessment. NERC 754 required us to do this with the understanding that if there was such a scenario, it would not be counted as a violation. Now they are adding this to a point that it would be a violation.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Need footnotes to explain why items like PT's and CT's are excluded.	
Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy disagrees with the further clarification. CenterPoint Energy recommends deleting item (b) in Footnote 13: "A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported." CenterPoint Energy's recommendation is based on the following:

•   The System Protection and Control Subcommittee (SPCS) and System Modeling and Analysis Subcommittee (SAMS), after performing an extensive analysis by their subject matter experts, did not recommend including communication systems in Footnote 13 (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request, September 2015).
•   A communication system was not part of the Standards Authorization Request as one of the non-redundant components of a Protection System to consider for inclusion in Footnote 13.
•   Monitoring communications equipment of communication-aided protections schemes is extensively utilized. In addition, NERC Standard PRC-005, Transmission and Generation Protection System Maintenance and Testing, encourages monitoring of communication systems, to avoid frequent manual testing, for entities that have no monitoring or entities that do not yet have monitoring of one hundred percent of their applicable communications systems.
•   The September 2015 SPCS/SAMS assessment noted that a communication system failure will not prevent high-speed tripping (i.e., does not result in Delayed Fault Clearing) for certain protection system designs, such as a directional comparison blocking scheme (DCB), which is extensively utilized.
•   Including communication systems in Footnote 13 results is a compliance burden that does not provide commensurate reliability benefits.

CenterPoint Energy comments on the wording of the Rationale for Table 1 P5 Event and Footnote 13 are as follows:

•   The first sentence of the first paragraph states an entity must model a single point of failure of a non-redundant Protection System component "that may prevent correct operation of a Protection System…" CenterPoint Energy recommends replacing this phrase with: "that will result in Delayed Fault Clearing associated with a failure to trip." CenterPoint Energy recommends deleting the second sentence: "The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time."
•   In the second sentence of the fourth paragraph, CenterPoint Energy recommends adding that the SPCS/SAMS report also described a communication system as having a lower level of risk of failure to trip.
•   CenterPoint Energy recommends review of the fifth paragraph and Footnote 13d. The fifth paragraph states the team sought to limit the scope of protective relays to those used for "primary protection," not including "backup protection." However, the terms "primary" or "backup" protection are not used in Footnote 13 that uses the NERC term Protection System. Based on the NERC Glossary definition, a Protection System at a substation for an Element could include two, or more, protection schemes whether the schemes are called primary/backup, primary/secondary, or scheme 1/scheme2.
•   CenterPoint Energy concurs with the wording of Footnote 13 item (a) of "A single protective relay," which does not include language that it applies only to protective relays "which responds to electrical quantities." This allows the use, if appropriate, of a sudden pressure relay as redundant for transformer differential protection. Sudden pressure relays were addressed by the SPCS (Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities - SPCS Input for Standard Development in Response to FERC Order No. 758, December 2013)

Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Item 2 goes beyond the scope of the SAR. Furthermore, specificity of the relay functions is preferred in order to eliminate the possibility of a different interpretation by an auditor.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

The SRC offers the following comments regarding clarification of relay components of a Protection System:

1) Clarity needs to be added to “single relay” to exclude instances where a second relay performing a different function is also installed.

2) Clarity needs to be added to “single communication system” to specify the devices that need to clear a fault as opposed to devices that may result in overtrip.

3) Clarity should be added to allow for redundancy provided by devices responding to non-electrical quantities.

4) Clarity should be added for what constitutes “not monitored” or “not reported” in the instances of communication system and DC supply.

5) Item #4 is unclear if it is requiring two trip coils. This needs to be clarified.

6) Do the trip coils need to be monitored?

7) It is not clear on how trip coils are to be evaluated. An application guide to provide more detail on and explain the proposed footnotes would be helpful. 8) Wouldn't the single control circuitry just be a concern up to the point of initiating breaker failure (not to the trip coil). In other words, as long as breaker failure is initiated, then the event would be captured under P4. 9) The parenthetical that specifies the different relay types should not be deleted because the term "single protective relay" is not specific enough. 10) While the revised footnote is an improvement, clarifications are still needed to properly identify the redundancy requirements. We believe that minimum design requirements or a guideline should be included in the standard. That will allow the Planning Coordinators/Transmission Planners to have a consistent interpretation of the footnote 13. 11) There are situations when non BES elements are connected to BES buses (e.g. radial circuits supplying loads). The standard must clarify which protection systems failures needs to be studied since an uncleared close in fault on a non BES element connected to a BES bus has the same consequence as an uncleared close in fault on a BES element. 12) Do the protection systems installed on non BES elements connected to BES buses and protecting portions of the BES buses need to meet redundancy criteria?

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
The FERC Order 754 SPCS report specifically recommended adding the components from the definition of protection system. Within that definition, protective relays are described as "Protective relays which respond to electrical quantities". This is an important distinction which is missing from the proposed addition/revision to footnote 13.	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
The footnote is unclear and requires additional clarity. After review by the System Protection Engineering group, they have determined that the drafting team's attempt to provide clarity falls short of its intent. Additionally The inclusion of 3phase faults in the Extreme events stability runs will require a substantial incease in the amount of stability files that need to be created, constantly reviewed, and ran on a regualar basis. This will greatly increase the burden on the TP.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
SNPD suggests replacing the entire footnote 13 with a simple statement "Fault followed by a failure of the Protection System resulting in delayed trip from local and remote substations." This objective would require an Entity to assess and validate potential event(s) within its Bulk Electric System. We also suggest the Drafting Team consider the loss of the station battery as an extreme event (Category P7) that causes no trip at the local station and the faulted event can only be cleared from remote trips (Delayed Fault Clearing.)	
Likes 0	
Dislikes 0	

Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	
Comment	
The clarification of relay to components of a Protection System along with the associated footnote 13 does add clarity to the category P5 Planning Events as well as extreme events.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Yes, but Item 4 of Footnote 13 needs clarification.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Idaho Power agrees with the further clarification of relay to components since Protection System definition includes: • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and • Control circuitry associated with protective functions	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes

Document Name	
Comment	
Comments: The clarification of relay to components of a Protection System along with the associated footnote 13 does add clarity to the category P5 Planning Events as well as extreme events.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak supports the clarified language.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	

KCP&L agrees the language provides clarification but there is opportunity for further clarity as detailed in KCP&L's response to Question 4.

Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	

1. Tacoma Power does not agree that all parts of the Protection System should be treated identically with regards to single point failures. As identified the order 754 final report, some protection system components such as protective relays, auxiliary relays, and DC circuits downstream of the DC panel branch circuit protection have been documented as common causes of actual single point failures. The final report also identifies that AC inputs and the station DC supply pose much lower risk of failure to trip. The attached table shows an alternative set of contingencies that would implement a more risk-based approach to single point failures of each kind of component in the protection system.

2. Tacoma Power proposes P5 include the more common kinds of failures of the protection system that include 1) Protective relays which respond to electrical quantities; 2) A single communications system, necessary for correct operation of protective functions, which is not monitored; and 3) Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

3. New P8 and P9 contingencies for EHV facilities would address the remaining less likely to fail components of the protection system including (1) Voltage and current sensing devices providing inputs to protective relays, (2) Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply). Since these kinds of components are less likely to fail, allowing interruption of firm transmission service and nonconsequential load should be allowed for all voltage levels.

The 754 report found that only 0.7% of 100-199 kV buses had adverse system response from a single point of failure whereas 20% of EHV buses had adverse system response from a single point of failure. This disparity indicates efforts mitigating single component failures should be focused on the EHV system. The new P8 and P9 (i.e. the proposed d-h extreme events) should apply to just EHV elements. Creating new events P8 and P9 would clarify that Corrective Action Plans are required for these contingencies whereas extreme events do not require CAPs. 4. Tacoma Power supports reformatting of Table 1, as it is currently quite confusing. 5. There appears to be confusion as to whether to monitor protection circuits, the battery bank or the main DC breaker for open circuit. Trip coil monitoring does not provide any assurance the batteries are connected. Furthermore, there appears to be a lack of publicly available evidence that battery open circuit monitoring substantially lowers the risk of the protection system failing to trip. Dual batteries may be more appropriate for many EHV applications. 6. Battery monitoring system cost roughly the same amount as the set of batteries they monitor. Imposing additional costs for battery monitoring systems may lead to utilities replacing battery banks less often. 7. If the SDT continues to include monitoring as a viable option, these additional clarifications are need: (1) battery open circuit monitoring is required, (2) every breaker/fuse in the DC system must be monitored if it is a single point of failure, (3) a single trip coil is a single point of failure and is not mitigated by having trip coil monitoring unless there is independent breaker failure control circuitry, (4) low voltage monitoring threshold for battery voltage shall be coordinated with the battery design to give indication with at least 50% of battery capacity remaining, (5) auxiliary type relays for loss of DC may not be sufficient for low voltage monitoring of the battery, although they may be used for monitoring for loss of DC, and (6) non-battery-based DC systems require redundancy and should be addressed in a separate bullet under Footnote 13. 8. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6. 9. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.

Likes 0	
Dislikes 0	

Response

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP believes events 2e-2h are significant enough to warrant their own category in the planning table (such as P8).	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
SNPD agrees with simulating extreme events for the Near-Term Planning Assessment Study so we can learn from and understand the constraints of the BES and we can share results for situational awareness and work jointly with our PC/TP/TOP to develop short-term solutions. However, while it is feasible to study and develop an awareness of the BES for the Long-Range Planning Cases, SNPD suggests the Drafting Team not require a Corrective Action Plan(s) for the Long-Range Planning Cases, as it is not practical to require an Entity to develop a Long-Term Corrective Action Plan for extreme scenarios for the 5-year and beyond planning cases.	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We conceptually disagree with *requiring* any mitigation for extreme events – this would be a deviation from the long-standing planning philosophy of assessing the risks and consequences to BES reliability for Category D contingencies (i.e. extreme events) and permitting the transmission planner to exercise its discretionary judgment to identify usage of any corrective action(s) to reduce system vulnerability to extreme events.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
We have three concerns with this addition in R4.6. First is that the appropriate location in the standard for determining what events require Corrective Action Plans is R2.7, not R4. The second concern is that no other extreme events currently mandate projects (CAPs) to address performance issues. FMPA can find no instance in which FERC ordered that assessments of failure of a component of a protection system with a three phase fault be required to be remedied with a CAP, and furthermore, we find no instance in the SPCS Order 754 report where this was stated either. By all accounts the explicit changes to Table 1 items 2e-2h and the changes to the P5 event should have addressed FERC's concerns and should have addressed the recommendations of SPCS in the Order 754 report. By including the new requirement R4.6, the drafting team is ostensibly concluding that any projects that are proposed to address 2e-2h will be inexpensive and "easy to fix". While that may be likely, it cannot be guaranteed. Throughought the standards and the standards development process, industry is routinely informed that standards are not mandating capital projects, but that is excactly what this requirement is doing. The third concern is that it will be difficult/complicated to demonstrate compliance with this requirement, for a number of reasons. First is that Cascading is nowhere near as cleanly defined and identified as "delayed clearing" is. Secondarily, if the goal of these simulations is now to find events that	

result in cascading, the table 1 criteria for identifying events that result in "delayed clearing" simply was not written with that goal in mind. It was written to look for events that have significant stability impacts/cause that cause disruptions within the power system. Delayed clearing does not equate to "cascading". Where this comes into play is in assessing R4.4 contingency lists, where the PC and TP exercise engineering judgment to select which events will be the most severe. Since the Table 1 criteria for 2e – 2h specifically require delayed clearing, the PC or TP may select events in different locations.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Extreme Events should not have mandated performance requirements. By their definition, Extreme Evenets are highly unlikely and the burden for mitigaton should be left up to the entities impacted.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	

The SRC does do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES, and exceeds the overarching objectives of achieving an adequate level of reliability. The intent of assessing extreme events is to get a feel of how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. To go so far as requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Simply put, it goes beyond the adequate level of reliability. It might be fairly safe to say that quite a few entities will fail the extreme event testing under certain anticipated conditions for which the BES is not designed to withstand. Hence the existing requirement to evaluate possible actions to reduce the likelihood or mitigate the consequences of the event is appropriate, but to develop and implement CAPs for events (e) to (h) in Footnote 13 will incur in significant cost over and above what's needed to meet the basic criteria. This is philosophically, and in principle, a non-starter. We respectfully request the drafting team not to add this part. Note: ERCOT does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	

Answer	No
Document Name	
Comment	
This change goes beyond the scope of the SAR. It essentially makes an Extreme Event equivalent to a Planning Event. Additionally, it is not clear whether the CAPs ever have to be built or if they just have to be on paper.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy disagrees with the proposed Requirement 4, Part 4.6, additions. CenterPoint Energy's disagreement is based on the following: • The SPCS and SAMS, after performing an extensive analysis by their subject matter experts, did not recommend requiring a CAP for a subset of Table 1 extreme events (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request, September 2015). • Requiring a CAP for a subset of Table 1 extreme events (footnote 13, 2e-2h) was not part of the Standards Authorization Request. • Requiring documentation of a CAP for a specific, limited subset of Extreme Events results in a compliance burden that does not provide commensurate reliability benefits. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, an evaluation of possible actions designed to reduce the likelihood, or mitigate the consequences and adverse impacts of the event, should be conducted the same as with any other Extreme Event analysis that concludes there is Cascading.	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
The intent of 4.6 is already covered by the proposed changes to the P5 Category definition and reference to footnote 13. For instance, the EHV BES level does not allow for non-consequential load loss for a P5 contingency. In addition, the last sentence of 4.5 states "If the analysis concludes there is Cascading caused by the occurance of extreme events…an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences…shall be conducted." This statement effectively requires the development of alternatives. If there is a desire to strengthen 4.5 for events which lead to cascading related to non-redundant protection systems then it could be done in 4.5.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
SMUD does not support the proposed changes; we do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES and exceeds the overarching objectives of achieving an adequate level of reliability. The concept of assessing extreme events is to obtain an understanding how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. Requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Any decision to assign resources in either prevention of an extreme event or the mitigation of impacts for an extreme event should be left to the discretion of the entities impacted rather than mandated by the standards	

Additionally, a corrective action plan implies a correction is necessary and could be interpreted as a mandatory action requiring full mitigation for impacts of the extreme events. Studies that evaluate the impact of these extreme events and identification of possible actions that would reduce the likelihood or mitigate the consequences of these event types, as appropriately covered in requirement R4.5.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
Language should be very specific that the Implementation plan period is only for development of the CAP and not implementation of the CAP. It reads as if this remains open until the CAP is closed.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the report from Section 1600 Data Request following Order No. 754. This Order was issued directing NERC and Commission staff to initiate a	

process to identify any reliability issues for system performance following the loss of a single BES Element which appeared in the legacy TPL (version 0) standards. The conclusion from the report has rightfully and adequately addressed the Commission's concern. In general, the proposed TPL-001-5 removes the ambiguity from the legacy TPL standards for protection system failures.

However, the proposed new Requirement 4, Part 4.6 adding the Corrective Action Plan goes beyond the recommendation from the Section 1600 Data Request report for Order No. 754. In addition, the conclusion of the above report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 for extreme events in TPL-001-4 Part 4.5 nor did the SAR authorize the SDT

to do this. Any cascading due to an extreme event is already addressed in the Commission approved TPL-001-4 in Requirement 4, Part 4.5 wherein an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is warranted. Besides, a cascading caused by the extreme event due to protection system single points of failure (Table 1 for P5 and extreme event – stability 2e-2h) is no different than a cascading due to any other extreme event (a cascading is a cascading; the end result is the same). And the Section 1600 Data Request report has very clearly put this in their conclusion in the second paragraph which is copied below verbatim:

"Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: 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."

The added clarification under Table 1 for Planning Event P5 and extreme event – stability 2e-2h along with footnote 13 sufficiently covers all the concerns that the Commission expressed in Order No. 754 as well as the conclusion and recommendation from the analysis for the same in the aforementioned report for the protection system single points of failure.

Besides, if Requirement 4, Part 4.6 goes into effect, there won't be any operational workaround on the cascading arising from such failures. The "only" Corrective Action Plan for these kinds of events is a new capital improvement project which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction efforts spanning 10-20 years. This is a high-impact, low-frequency event risk that the industry, in order to identify and mitigate significant reliability risks, should develop action plans to reduce the likelihood or mitigate the consequences from such events keeping in mind their resources and budget which is already addressed in Requirement 4, Part 4.5.

Suggestion: Requirement 4, Part 4.6 is not needed.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
See comment #3.	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Also, the rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onereous. This scenario with a SLG fault is onerous enough. The requirements in the Extreme Events Table 2e-h should be depicted in Table 1 Planning Events as a second Row of P5 with three-phase as the "fault-type" for several reasons: 1. Table 1 note (a) already covers "cascading" not being allowed – maybe eliminating the need for a new R4.6 altogether 2. Clearly shows this as a signitifcant "raising-the-bar" event requiring a CAP 3. Maintains the separation between Planning Events (requiring a CAP) and Extreme Events (requiring analysis and optional CAP An alternative to it being depicted as a second row of P5 with three-phase as the "fault type" could be to make a P8 for stability only.	
Likes 0	

Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
This is a duplication of R4.5. This is not identified in FERC order 768, we find no clear need for this additional language. Furthermore extreme contingencies have not required formal corrective actions plans, this may result in unduly burdensome activities for rare and unlikely events.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) Requirement R4 focuses on the performance of Contingency analyses reflective of Table 1 by applicable entities. We believe the development of a Corrective Action Plan to address a potential Cascading event, in the Transmission Planning Horizon, should be included as a separate requirement. The Correction Action Plan should account for all viable solutions, including the delay of implementing corrective actions until specific operating conditions have been met, as such actions could require significant capital investment to implement. (2) The SDT should clarify the reference to “Cascading” as only those Elements which pertain to the BES definition. By its current application, the reference could include any Element, including non-BES Facilities.	

(3) Furthermore, while the inability to implement a Corrective Action Plan could directly and adversely affect the electrical state or capability of the BES, thus aligning it with the criteria of a Medium Violation Risk Factor, the development of the plan, as proposed, does not. We believe the failure to develop a Corrective Action Plan is administrative in nature and constitutes a Lower Violation Risk Factor in the Long-Term Planning Horizon.

(4) Based on our experience, we have seen a shift in the development of Reliability Standards towards referencing terms like “Element” and “Facility” to collectively align with the BES definition. We propose removing references to “System” to both requirement parts and reword Part 4.6.1 to “List deficiencies and the associated actions needed to prevent Facilities from Cascading.”

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	No
Document Name	

Comment

This subset of extreme events involves only 3Ø faults on various elements. In the presence of a Protection System SPF, this fault type may not be the most critical. The rational seems to anticipate that the revised criteria will be most applicable to legacy Protection Systems, since most newer PS are already designed using a higher level of redundancy. Many of the PS for these older schemes use single phase electromechanical or solid state relays. For such PS, a single relay failure would often not impact the ability to detect and clear a 3Ø fault, because two phase relays would still detect the fault and intiate clearing in the normally expected time *as though no relay failure had occurred*. The SPCS/SAMS report briefly alludes to this condition, but does not address an important System implication. A SLG fault on the same phase as the failed relay would not be detected within the primary protection zone and would result in delayed clearing. Of course, the number (System risk exposure) of SLG faults is much higher than for 3Ø faults. In most cases the same facilities are removed from service whether the delayed fault clearing results from a SLG or 3Ø fault. So, while it may initially sound counter intuitive, the more numerous SLG fault may actually have worse System impact than the 3Ø fault case with SPF.

- Does the drafting team interpret such SLG faults with Protection System failure as P5 (not extreme) events?
- If not, does it promote System reliability to not study the SLG fault case?

- If so, should another item be added to the list? The idea for such an item might read something like: If the non-redundant PS is implemented including single phase or ground relays, the e-h Element faults must also be studied for SLG faults with delayed fault clearing.

NVE would also like to suggest rewording Section 2 of the Stability portion of the Extreme Events table to help reduce wording,

2. Local or wide area events affecting the Transmission System such as:

- 3 phase fault on on any of the following equipment with stuck breaker resulting in Delayed Fault Clearing:

  - Generator

  - Transmission circuit

  - Transformer

  - Bus section

- 3 phase fault on any of the following equipment with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing:

  - Generator

  - Transmission circuit

  - Transformer

  - Bus section

Likes 0	
Dislikes 0	

Response

Scott Downey - Peak Reliability - 1

Answer	No
Document Name	

Comment	
The proposed requirement R4.6 represents a major shift with regard to extreme events. The current TPL-001-4 requires that extreme events be studied, but there are no performance requirement for these extreme event Contingencies, and these extreme event assessments do not result in Corrective Action Plans (CAP). According to the proposed set of requirements, if extreme events result in Cascading, a CAP must be developed that would prevent those extreme events from resulting in Cascading. Today, extreme events do not drive the development of CAPs; if this requirement as written is approved, extreme events will drive the development of CAPs. Peak's major concern with this requirement is any implied expectation for extreme events to be included and protected against in operations (including outage coordination assessments, OPAs, and RTAs). Such an expectation would have devastating consequences (economic consequences and reliability consequences) for operations. Given the implied potential for such operational expectations, Peak disagrees with the proposed requirement. Example. Let's say that a Planning Assessment includes a few planned outages and that the Planning Assessment indicates that an extreme Contingency results in Cascading. If the outage weren't in place, the extreme Contingency would not result in Cascading. The TP isn't going to build anything to address that Cascading, because it's a temporary condition due to the outage. So the TP creates a CAP which is an Operating Plan to "fix" it. Fast forward to operations. Is it presumed that this extreme Contingency is now credible for operations and that the system needs to be operated in a manner that prevents the extreme Contingency from resulting in Cascading? Peak is VERY reluctant to endorse any kind of planning standard that in any way can be perceived to dictate to operations which Contingencies (beyond single Contingencies) must be protected against in operations…ESPECIALLY extreme event Contingencies. This approach removes the ability of the RC and TOPs within the RC Area to operate the system to manage risk when it comes to deciding which Contingencies beyond single P1 Contingencies need to be protected against. Peak believes that Planning Assessment of extreme event Contingencies and the resulting development of an associated CAP should in no way imply that those extreme event Contingencies need to be protected against in operations.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	

Traditionally the intent of "extreme events" or "extreme contingencies" was to create awareness of the impacts of the studied contingencies, but not establish design requirements. Therefore, we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes:

Category: P8 Multiple Contingency

Initial Condition: Normal System

Event: 2e through 2h

Fault Type: 3 phase

BES Level: HV, EHV

Interruption of Firm Transmission Service Allowed: Yes

Non-Consequential Load Loss Allowed: Yes

With this change, Requirement R4.6 should be revised as follows: "If the analysis concludes there is Cascading caused by the occurrence of Table 1 planning events P8, a Corrective Action Plan shall be developed…."

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

From our perspective, requiring the development of corrective action plans to include redundant relaying for extreme events is inconsistent compared with the existing TPL-001-4 requirements. Corrective action plans should include upgrades to meet planned events and local transmission planning criteria, but not for extreme events that have a very low probability of occurrence. If NERC/FERC wants redundant system protection systems to address these extreme events, then these requirements would be better suited to a PRC standard, and not a TPL standard. Transmission Planners should not be burdened with identifying which circuits are critical for which season or system condition so that protection engineers must install redundant system protection systems, which may only be needed for limited and specific system conditions.

We believe that further clarification is needed on Stability item 2f from Table 1 – Extreme Events. We believe that the terms "close-in" should be added to item 2f, so that it reads "3-phase close-in fault on Transmission circuit with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing". We believe this change would reduce the number of scenarios that would need to be investigated from a stability perspective. Further, FERC Order 754 study only looked at close-in line and bus faults with remote clearing. For end of line 3-phase faults, fault detection is unlikely with a failure of a non-redundant System Protection Component due to in-feed effect. Therefore, it may not be possible to perform a reasonably valid stability study with this indeterminate state. If so, we believe that corrective action plans may be burdensome to complete. Given the low probability of a battery failure concurrent with a 3-phase end of line fault, we believe that inclusion of such events in the basic planning requirements is inconsistent.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC

Answer	No
Document Name	

Comment

A 3-ph fault is a very low probability event and should be mitigated through operating plans if the contingency shows that it results in cascading just like the other extreme events. PacifiCorp agrees that a list of reliability issues for the extreme events (2e-2h) should be developed such that operating plans can be developed, but requiring system upgrades as part of a corrective action plan is a significant burden on utilities without added benefit over an operating plan. Hence PacifiCorp recommends the drafting team remove the requirement of having a corrective action plan for such a rare event.

Likes 0	
Dislikes 0	

Response

Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: This requirement goes beyond the recommendation from the Section 1600 Data Request report for Order 754. The report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 R4 Part 4.5 for extreme events. Additionaly, the SAR did not authorize the SDT to do this. Recommend removing R4 Part 4.6.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Requirement 4.5 of the TPL-001-4 standard has specified for the TPs/PCs "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". There is no justification given for why these particular extreme events should have more stringent requirements than other extreme events. A Corrective Action Plan (CAP) for extreme events should not be necessary, can be costly, and may not produce much benefit because of the low frequency of these type of events from happening. Suggestion: The addition of requirement 4.6 is not needed.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC does not agree with requiring the development of Corrective Action Plans (CAPs) for extreme stability 2e-2h events, or any other extreme events. We believe that the distinction between developing CAPs for “planning events” and not for “extreme events” is to recognize that the probability of extreme events is too low and the **cost to benefit ratio is too high to require the development of CAPs.** Part 4.5 already requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for all extreme stability events, including extreme stability 2e-2h events if there is Cascading. In addition, Part 3.5 also requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for extreme steady state events and there is no proposal for a Part 3.6 to require CAPs for any subset of steady state extreme events. (1) Is the intent of these CAPs to understand the scope of resolving the impact of the Extreme Events or to spend capital to resolve the issues?	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
As stated in question 3, NIPSCO believes the addition of these components will involve most BES facilities. This will create more extreme type contingencies involving loss of a complete substation. Requiring a CAP on an extreme contingency on the amount of BES substations involved will lead to unreasonable mitigation costs. NIPSCO believes the requirement for all extreme events should suffice and the addition of proposed Requirement 4, Part 4.6 is unnecessary.	

If the intention of the SDT was to require a plan of action, with no time limit on acting on these plans, as Part 4.6 reads, then again, the current requirement for all extreme events should suffice.	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
As stated in response to Question 3 and repeated for emphasis, IEEE recommended practices are used in designing typical generator protection schemes. Prevailing protection schemes (based on IEEE Standards) for a majority of generators that are in service may not have completely redundant protection schemes as clarified by proposed footnote 13. It may not be practical for GO/GOP to implement a completely redundant protection scheme. For example, it may not be physically possible to install additional CTs on the generators or redundant battery systems. The Standard Drafting Team should develop an application guideline with appropriate figures to clarify the Standard Drafting Team's goal with this clarification. Refer to Figure 1.1 of NERC Technical Reference Document , "Power Plant and Transmission System Protection Coordination (http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf) Also, GO/GOP may not be able to implement corrective action schemes identified by the TP.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	

Comment	
For Table 1 Stability Performance events 2b, 2c, 2d, 2f, 2g, and 2h it is required to simulate a 3-phase fault. This contradicts with the fault type (single-line-ground) recommended for category P5 in the same Table.	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The concern is that the method the drafting team chose to implement the language seems out of order with the technical nature and system planning intent of Extreme Event contingency analysis. A better solution might be to create a new contingency category (e.g., P8) for 3 phase faults coinciding with protection system failures and also add the corresponding requirement under R2 where failure to meet the performance thresholds from R6 require a Corrective Action Plan. This will align with other TPL contingency analysis and also allow for Planning Coordinators to define more tailored mitigation requirements for its Planning Coordinator area. Additionally, putting the Corrective Action Plan requirement under R2 aligns with other Table 1 performance violations.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	

Comment	
Although PGE agrees that these single points of failure should be studied and identified, PGE does not agree with the requirement to develop a Corrective Action Plan. Corrective Action Plans are associated with capital improvements to add redundancy to the system. Adding redundancy to the system does not eliminate the possibility of an event, it only reduces the likelihood of the event. PGE recommends that utilities be given latitude to determine acceptable risk tolerances for events based on the likelihood of an event occurring and the consequence of that event. For example, it may be more likely for two old and unmaintained batteries to fail when called upon to act than one new and tested battery. The first case meets the requirement of the standard, while not providing system resiliency while the second would not meet the standard but could be a more economical and effective solution. The addition of a second battery to an existing substation could require rewiring or replacing existing relays or control buildings, replacing existing single trip coil breakers, and new trench systems. The cost of adding a second battery could be very high compared to alternative of assessing and managing the health of an existing battery to reduce the likelihood of failure. PGE recommends that the TPL standard offer performance criteria requirements in place of design requirements such as duel battery systems via Corrective Action Plans. The inclusion of Footnote 13.2 *A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported* may have unintended consequences. If a utility has implemented transfer trip to improve coordination, but not because transfer trip is required for system stability, a utility might elect to disable transfer trip rather than incur the addition costs of demonstrating compliance with this requirement. As an alternative, it may be more beneficial to require that the critical clearing time for all facilities be studied, and entities are required to report facilities with critical clearing times greater than that of the backup protection where there is a non-redundant communication path, and to develop Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	Project_2015-10_TPL-001-5_Unofficial_Comment_Form_V3 Planning Final.docx
Comment	

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the “or” in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

1. Local or wide area events affecting the Transmission System such as:

    i. 3Ø fault on generator with stuck breaker10 resulting in Delayed Fault Clearing.

    ii. 3Ø fault on Transmission circuit with stuck breaker10 resulting in Delayed Fault Clearing.

    iii. 3Ø fault on transformer with stuck breaker10 resulting in Delayed Fault Clearing.

    iv. 3Ø fault on bus section with stuck breaker10 resulting in Delayed Fault Clearing.

    v. 3Ø fault on generator with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    vi. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    vii. 3Ø fault on transformer with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.

    viii. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System13 resulting in Delayed Fault Clearing.

    ix. 3Ø internal breaker fault.

    x. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report: · *Place additional emphasis on assessment of a three-phase fault and protection system failure* o *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated* · *Elevate to a planning event with its own system performance criteria* o *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event* · *Keep as an extreme event with no change (other than footnote 13)* o *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments* From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a "subset of Table 1 Extreme Events" be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because "the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event". Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events. Although WAPA strongly disagrees with requiring a Corrective Action Plan for this "subset of Table 1 extreme events", if this requirement is carried forward WAPA recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events. **(see uploaded file Q/A #4)**

Likes 0	
Dislikes 0	

Response
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC

Answer	No
Document Name	

Comment	
Since a Corrective Action Plan is not required, there is no need to create one. Corrective Action Plans would “gold plate” the system for very unlikely events.	
Likes 0	
Dislikes 0	
Response	
ALAN ADAMSON - New York State Reliability Council - 10	
Answer	No
Document Name	
Comment	
We agree that an evaluation of a list of system deficiencies and associated actions needed to prevent the system from cascading for extreme events 2e-2h should be required; however, we disagree that TPL-001-5 should further require implementation of Corrective Action Plans to mitigate these extreme events. Instead, Transmission Planners and Planning Coordinators should be required to consider implementing actions – recognizing cost and other factors – to reduce the likelihood or completely avoid the consequences of these extreme events.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] 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

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
  - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*
  - *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*

- *Keep as an extreme event with no change (other than footnote 13)*
    - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a “subset of Table 1 Extreme Events” be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because “the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event”. Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although Corn Belt strongly disagrees with requiring a Corrective Action Plan for this “subset of Table 1 extreme events”, if this requirement is carried forward Corn Belt recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Likes 0	
Dislikes 0	

Response

John Babik - JEA - 1,3,5

Answer	No
Document Name	

Comment

The clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the report from Section 1600 Data Request following Order No. 754. This Order was issued directing NERC and Commission staff to initiate a process to identify any reliability issues for system performance following the loss of a single BES Element which appeared in the legacy TPL (version 0) standards. The conclusion from the report has rightfully and adequately addressed the Commission’s concern. In general, the proposed TPL-001-5 removes the ambiguity from the legacy TPL standards for protection system failures.

However, the proposed new Requirement 4, Part 4.6 adding the Corrective Action Plan goes beyond the recommendation from the Section 1600 Data Request report for Order No. 754. In addition, the conclusion of the above report did not recommend setting the bar “higher” for performance than it is for current TPL-001-4 for extreme events in TPL-001-4 Part 4.5 nor did the SAR authorize the SDT to do this. Any cascading due to an extreme event is already addressed in the Commission approved TPL-001-4 in Requirement 4, Part 4.5 wherein an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is warranted. Besides, a cascading caused by the extreme event due to protection system single points of failure (Table 1 for P5 and extreme event – stability 2e-2h) is no different than a cascading due to any other extreme event (a cascading is a cascading; the end result is the same). And the Section 1600 Data Request report has very clearly put this in their conclusion in the second paragraph which is copied below verbatim:

"Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5. From TPL-001-4, Part 4.5: 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."

The added clarification under Table 1 for Planning Event P5 and extreme event – stability 2e-2h along with footnote 13 sufficiently covers all the concerns that the Commission expressed in Order No. 754 as well as the conclusion and recommendation from the analysis for the same in the aforementioned report for the protection system single points of failure.

Besides, if Requirement 4, Part 4.6 goes into effect, there won't be any operational workaround on the cascading arising from such failures. The "only" Corrective Action Plan for these kinds of events is a new capital improvement project which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction efforts spanning 10-20 years. This is a high-impact, low-frequency event risk that the industry, in order to identify and mitigate significant reliability risks, should develop action plans to reduce the likelihood or mitigate the consequences from such events keeping in mind their resources and budget which is already addressed in Requirement 4, Part 4.5.

Suggestion: Requirement 4, Part 4.6 is not needed.

Likes 0	
Dislikes 0	

Response

Mark Holman - PJM Interconnection, L.L.C. - 2

Answer	No
Document Name	

Comment

A corrective action plan should not be "required" for a combination of low probability events (3 phase fault coupled with a relay failure)

Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA believes the occurence of a three-phase fault including a protection system failure would have an extremely low probability of occurring. As such, requiring implementation of a corrective action plan to fix these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that past performance can be a good indicator of future performance. These types of outages have not been an issue in the past. BPA believes that it is not economically justifiable to require corrective action plans for low probability extreme events like these. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system.	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
Similar to our response to Q3, AEP believes that pursuing Corrective Action Plans as part of R4, Part 4.6 goes beyond the scope of the current SAR. Once again, we believe such an inclusion should not be considered until the SAR has been appropriately revised, and industry afforded opportunity to provide comment on the suggested change. As to the concept itself, AEP does not agree that Correction Action Plans would be justified or necessary in every case. Considerations such as the nature and/or extent of any potential cascading should be a factor in determining whether or not a CAP is necessary, but as currently written, the obligation does not allow such engineering judgment.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	No
Document Name	
Comment	
SDG&E is not against trying to simulate the extreme contingency events listed in Table 1, 2e-2h, but simulations of extreme events often end with a simulation failure. TPL-001 is a mandatory requirement and this makes section 4.6 binding on the TP/PC. If a simulation fails, the TP/PC will have no choice but to create a Corrective Action Plan. Regardless of cascading.	
Likes 0	

Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
There are concerns with requiring the development of Corrective Action Plans (CAPs) for extreme stability 2e-2h events, or any other extreme events. The distinction between developing CAPs for “planning events” and not for “extreme events” is to recognize that the probability of extreme events is too low and the cost to benefit ratio is too high to require the development of CAPs. Part 4.5 already requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for all extreme stability events, including extreme stability 2e-2h events if there is Cascading. In addition, Part 3.5 also requires the evaluation of possible actions to reduce the likelihood or mitigate the consequences for extreme steady state events and there is no proposal for a Part 3.6 to require CAPs for any subset of steady state extreme events. Is the intent of these CAPs to understand the scope of resolving the impact of the Extreme Events or to spend capital to resolve the issues? The NSRF suggests the SDT mine the Event Analysis data to determine how many dynamic stability events occurred due to the lack of a redundant protection system component covered under Footnote 13. The benefit is the reduction and severity of events, while the costs could be significant.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	

Traditionally the intent of “extreme events” or “extreme contingencies” was to create awareness of the impacts of the studied contingencies, but not establish design requiements. Therefore we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes: Category: P8 Multiple Contingency Initial Condition: Normal System Event: 2e through 2h Fault Type: 3 phase BES Level: HV, EHV Interruption of Firm Transmission Service Allowed: Yes Non-Consequential Load Loss Allowed: Yes With this change, Requirement R4.6 should be revised as follows: “If the analysis concludes there is Cascading caused by the occurrence of **Table 1 planning events P8**, a Corrective Action Plan shall be developed…..”	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We do not agree with the addition of Requirement 4, Part 4.6. We believe this addition contradicts with the basic design, planning and operation criteria of the BES, and exceeds the overarching objectives of achieving an adequate level of reliability. The intent of assessing extreme events is to get a feel of how the system would perform under such conditions. Where possible, actions could be speculated or designed to mitigate the adverse impact, as already mandated in Part 4.5 of the existing TPL-001-4 standard. To go so far as requiring corrective action plans (CAP) to prevent or reduce the occurrence (such as by duplicating the non-redundant component) goes beyond the basic criteria for the design, planning and operation of the BES. Simply put, it goes beyond the adequate level of reliability. It might be fairly safe to say that quite a few entities will fail the extreme event testing under certain anticipated conditions for which the BES is not designed to withstand. Hence the existing requirement to evaluate possible actions to reduce the likelihood or mitigate the consequences of the event is appropriate, but to develop and implement CAPs for events (e) to (h) in	

Footnote 13 will incur in significant cost over and above what's needed to meet the basic criteria. This is philosophically, and in principle, a non-starter. We respectfully request the drafting team not to add this part. However, if the SDT wants to proceed with its proposed approach the following needs to be clarified: This requirement creates ambiguity in studying events. Though the standard requires studying three phase faults, there is no indication about the fault location which influences whether cascading will occur. Generally in the planning studies the faults are applied on the buses since they produce more severe system impacts. When the "component failure of a Protection System" is considered and studied, a bus fault or a close in fault may still be cleared remotely by the back up protections (remote 21 timed, 51, 51N etc.) and Cascading may not occur. When the fault location is moved along the circuits there may be locations, where the fault will remain uncleared, since the remote back up protection systems may not be able to detect the fault, creating conditions for cascading to occur. Planning Engineers are familiar with the protection systems' behavior when they operate as expected. In case the intent of the standard is to study faults at any location (e.g. away from a substation bus) on circuits protected by a nonredundant protection system , then the planning assessment will require additional info from protection system owners (e.g. the performance of the remote backup distance elements required to clear faults while the local protection systems experience single component failure; this is not presently documented for all fault locations that potentially can cause cascading). If this is the intent of the requirement, then the standard should include specific requirements for protection system owners to provide necessary data to the planners.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the content but sees an opportunity to improve clarity by making the specific extreme event a separate category of contingency. A Corrective Action Plan (CAP) is required only in the case of the described specific extreme event identified in the question as "a subset of Table 1 extreme events." Making a separate contingency category sets it apart and highlights the CAP requirement. We believe, in this instance, there is value in emphasizing the required response of completing a CAP in the event of the described extreme event.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group suggests that the drafting team review sections 2F–2H be applicable to EHV level facilities. For example, the new stability extreme event in table 1, 2F, should be revised to state, 3Ø fault on Extra High Voltage (EHV) level Transmission circuit with failure of a non-redundant component of a Protection System13 resulting in Delayed Fault Clearing.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The SRC agrees with the proposed addition of Part 4.6.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
While less probable than single-phase-to-ground faults, three-phase faults are single events and single-phase-to-ground faults will often evolve into three-phase faults under severe delayed clearing scenarios such as a P5 contingency. Therefore, to the extent these extreme events cause cascading, it may be prudent to require a corrective action plan. However, consideration should be given to handling this as a Table 1 P8 contingency where the performance requirement is simply no cascading or loss of stability. This is a cleaner way to address this issue because it does not introduce additional performance requirements for the extreme event category.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Tacoma Power disagrees with the concept of requiring CAPs for extreme events. If events are critical enough to need a CAP, they should be listed as required contingencies. Please see our comments to question 2 with regard to which events at which voltage levels should have CAPs.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Due to referencing RC in the proposed requirement 1.1.2, it should be added as an applicable entity if the proposal is adopted, however, the RC should not have any involvement in the near-term planning timeframe. Also, TO needs to be added as an applicable entity if the three phase fault is moved along the circuit to determine the location for cascading as explained in Q4 above.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
As mentioned in our comments to Question #1, , we would suggest the SDT investigate the possibility of taking a step back and altering proposed requirement 1.1.2 to make it applicable to a TOP and also a TP. The TOP may be in the best position to be aware of known / planned outages in the near term planning horizon, and to be able to identify such outages to the TP. As stated in the rationale, the goal is not to consider hypothetical outages. The TOP may be in the best position to identify known / planned outages, prioritize them in terms of reliability impact, and then them provide to the TP for analysis in the annual near term planning horizon planning assessment. If the TOP is not the right applicable entity to share this requirement with the TP , then perhaps the RC is the correct entity.	

Consistent with this suggestion, we would note that the ERO Enterprise-Endorsed Implementation Guidance for TPL-001-4 mentions, for Req #1.1.2, the practice of obtaining “known outages information from applicable (in its area or in an adjacent area) Reliability Coordinators (RCs), Generator Operators (GOPs), or Transmission Operators (TOPs).”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
If the SDT does not accept our comment to clarify and revise R1.1.2 and R2.1.3, then then the applicability of TPL-001 must be expanded to include the RC, to ensure the RC “consults” with the TP. TO and GO that own Protection Systems should be added to applicability, so that those entities are required to provide the necessary Protection System information to the Transmission Planner so the TP can perform the Planning Analysis.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
RC should become an applicable entity.	

Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	
Comment	
For meeting the compliance for Requirement R1 – part 1.1 – subpart 1.1.2 and for Requirement R2 – part 2.1 – subpart 2.1.3, the cooperation of the RC is required by PCs and TPs. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. Hence, inaction from RC can expose PCs and TPs to possible violation with these sub-requirements. Instead **IRO-017 Outage Coordination** standard is a better venue to address FERC's concern from Paragraph 40 and **TPL-001** standard should be maintained solely as a *true* Transmission Planning Standard. **Suggestion**: Address this in a future revision of IRO-017.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Corn Belt agrees with the SPP Standards Review Group proposal that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017.	

Corn Belt agrees with the SPP Standards Review Group suggestion that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP develop Corretive Action Plans (CAPs).	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
In addition to response to question 1 regarding inclusion of RC, GO/GOP should also be included. If the TP identifies a Corrective Action Plan which involves adding redundancy to generator protection relays, they cannot require that the GO implement that plan.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The standard should not involve the RC. However, the standard should direct the PC or TP to consult with the TO to determine whether or not specific facilities are applicable to P5 contingencies based on single points of failure and how the remote backup protection would respond for a P5 contingency in terms of sequence of events, clearing times, and additional facilities tripped, and reclosing. Perhaps the TO should be an applicable entity responsible for	

defining and providing the P5 contingency definitions to the PC and TP. Protection system are complex and often vary across a system, so protection engineers should be involved in defining the details of P5 contingencies.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra

Answer	No
Document Name	

Comment

If the SDT does not accept our comment to clarify and revise R1.1.2 and R2.1.3, then then the applicability of TPL-001 must be expanded to include the RC, to ensure the RC “consults” with the TP. TO and GO that own Protection Systems should be added to applicability, so that those entities are required to provide the necessary Protection System information to the Transmission Planner so the TP can perform the Planning Analysis.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

Depending on how R1, Part 1.1.2 is revised, the RC may have an obligation to provide consultation to the TP/PC, or otherwise the TP/PC can be assessed non-compliant if the RC does not respond to the TP/PC’s requests. Therefore the RC should be a responsible entity.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy requests further clarification from the SDT on the rationale to leave the RC out of the applicability of this standard. If TPL-001-5 R1.1.2 remains as is in the proposed standard, then the RC must appear in the Applicability portion of the standard. The RC has an explicit role to determine what outages must be studied, not a role as a consultant. Outages are not singular isolated events. Outages occur in combinations and under varying system conditions. The RC, not the transmission planner, has the more appropriate background knowledge and skill set to make the best determination on what to study. Neither the proposed TPL-001-5, nor the existing IRO-017 make clear the RC has lead responsibility that it should for ensuring proper evaluation and coordination of outages has been performed. We understand that it is inferred that IRO-017 covers this action from the RC. Even there the responsibility is only on the PC/TP to jointly develop solutions with its RC for identified issues or conflicts. No explicit language in IRO-017 exists that requires the RC to provide the outage that must be studied to the PC/TP. We reiterate that actions requiring operational personel to perform work should rest in an operational standard.	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	

Due to the emphasis on planned maintenance outages it is important that the parties which will provide the known outage information to the Planning Coordinator and Transmission Planner be assigned to the Reliability Standard to ensure that information is provided in a timely manner. This may include the Reliability Coordinator, Tranmission Operator, Transmission Owner, Generator Owner or a combination of those functional entities. Additionally the Transmission Owner should be included for purposes of single point of failure due to non-redundant Protection System elements. Finally, Distribution Provider should be added anywhere Load Serving Entity is mentioned.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The proposed “consultation” approach, as currently drafted, raises a number of issues. Most critically, the proposed standard imposes no compliance obligations on the RC, but permits the TP and PC to exempt certain projects by “consulting” with the RC, which implies action by the RC. As such, a PC or TP could potentially omit certain P1 contingencies from their annual Planning Assessments and then provide that information to the RC. The TP and PC do not have to obtain the RC’s consent or approval to the proposed omissions. Thus, merely providing this information arguably constitutes a “consultation” under the Standard. The RC in turn is under no affirmative obligation to act on that request. As a result, P1 contingencies could not be modeled and may not have been fully considered by the RC, but the resulting Planning Assessment would still comply with the standard. Given this fact, the proposed extension of a “consultation” process to all planned outages raises a number of issues and is over broad. Texas RE suggests the SDT clarify what constitutes a valid consultation and should at a minimum limit the application of a “consultation” exemption to planned outages with a duration of less than six months.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	
Comment	

The SPP Standards Review Group proposes that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017.

The SPP Standards Review Group suggests that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP develop Corretive Action Plans (CAPs).

Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	
Comment	

For meeting the compliance for Requirement R1 – part 1.1 – subpart 1.1.2 and for Requirement R2 – part 2.1 – subpart 2.1.3, the cooperation of the RC is required by PCs and TPs. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. Hence, inaction from RC can expose PCs and TPs to possible violation with these sub-requirements. Instead **IRO-017 Outage Coordination** standard is a better venue to address FERC's concern from Paragraph 40 and **TPL-001** standard should be maintained solely as a *true* Transmission Planning Standard.

Suggestion: Address this in a future revision of IRO-017.

Likes 0	

Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	No
Document Name	
Comment	
Depending on how R1, Part 1.1.2 and Part 2.1.3 are revised, the RC may have an obligation to provide consultation to the TP/PC, or otherwise the TP/PC can be assessed non-compliant with the part if the RC does not respond to the TP/PC's requests.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
The RC should be included. Omitting the RC removes any compliance responisiblity for the RC and places it soley on the PC and TP.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
If the standard is calling for PC/TP collaboration/coordination, etc. with other functional entities, applicability of the TPL-001-5 standard should also apply to those other entities (e.g. RC) so they have a vested interest in collaborating with the PC/TP.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	Yes
Document Name	

Comment	
SDG&E agrees with the SDT, but SDG&E is concerned that the role the RC, TOs, GOs and DPs is not well defined with respect to TPL-001. If the SDT keeps the reference to the Reliability Coordinator in section 1.1.2., then the Reliability Coodinator should be added as an applicable entity.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
If the proposed changes to Requirement 1, Part 1.1.2 are adopted, RCs should be added to the applicability of the standard, because PCs/TPs would need to rely on the cooperation of RCs. As indicated in response to question 1, we do not agree with the proposed changes to R1.1.2.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Comments: We recommended removing the Reliability Coordinator from having a compliance obligtation with this standard. Therefore, we agree that they should NOT be added as an Applicable Entity. This standard should remain a Planning Standard and should not require involvement from the Reliability Coordinator.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
The current proposed standard has requirements that are applicable only to the PC and TP; therefore, it makes sense to have the standard itself applicable only to PCs and TPs. It doesn't make sense to do it any other way. Therefore, the standard needs to remove implied requirements for the RC to consult with the PC/TP.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

The question is inconsistent with commonly used abbreviations for functional entities. What functional entities are the SDT referencing and did not include in the applicability of this standard? Is the SDT attempting to refer to Transmission Owners (TO) versus Transmission Operators (TOP) and Generator Owners (GO) versus Generator Operators (GOP)? Nonetheless, we believe the applicability section should be reflective of only those entities that are required to maintain system models and conduct analytical studies identified within the standard.

Likes 0	
Dislikes 0	

Response
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company

Answer	Yes
Document Name	

Comment
Its seems strange to bring the RC into the planning world when the Standard does not apply to that function, and the RC is not a responsible entity. To eliminate this, including potentially adding the RC as a responsible entity in this standard (R1), remove the RC language as proposed above in the response to Question 1. But if the RC is included, our recommendation would be for Requirement 1, Part 1.1.2 to state "request known outages from the RC to be considered for analysis."

Likes 0	
Dislikes 0	

Response
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE

Answer	Yes
Document Name	

Comment

KCP&L agrees with the drafting team's approach.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Yes, SNPD agrees with the Drafting Team's approach which does not add additional applicable entities to the applicability of the standard.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
If the drafting team moves forward with the proposed change to move away from the 6 month outage duration, the list of applicable entities should be expanded to include RC and TO (Transmission Owner).	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
Tacoma Power agrees with the drafting team, provided that the Reliability Coordinator's role under Requirement R1, Part 1.1.2, is only advisory.	

Likes 0	
Dislikes 0	
Response	

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We don't agree that these changes are required to perform the assessment. We do agree that a complete refurbishment of the standard should be completed, with NERC holding technical discussions in an open forum as was done with other standards.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Plans and budgets are typically evaluated for at least a 5 year window. Adding requirements that could afect these plans should allow a similar length of time to implement. The minimum implementation perios should be 60 months.	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI disagrees with the proposed requirements, and therefore disagrees with the 36 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The 36 month implementation period is too short of a time to address all requirements except Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions. The 60 month implementation plan for everything doesn't create any confusion on which requirements need to be implemented and gives the planning engineer(s) more time to make sure all requirements are addressed in their annual planning assessment.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	

Comment	
Based on our comments requesting additional clarity be provided on redundancy and its levels, as well as what is meant by “single communication system”, we cannot agree with the 36 month implementation period, until said clarification is provided. It is not possible to know if 36 months, or 60 months is adequate unless the scope of work is clearly understood by industry stakeholders. Once additional clarity is provided, expectations will be clearer, and level/scope of work will be more easily determined.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
By providing oly 36 months to accomplish these requirements, it would force TOs to essentially perform simulations at all locations, assuming that relay redundancy does not exist anywhere, rather than determine first where relay redundancy does not exist and limit the scope of transient stability simulations to those locations.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

SCL disagrees with the proposed requirements, and therefore disagrees with the 36 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
This question is not applicable. NIPSCO does agree with the proposed changes in the question.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	

SNPD is however, somewhat concerned with the 36 month implementation period to address **All Requirements** except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5, because our budget approval process may require 1-2 years and the construction period may need 5-7 years. It would be more practical for the Drafting Team to suggest an implementation plan with the following items:

- Provide Project Goals and Objectives
- Provide a List of Tasks, and Tentative Schedules

Likes 0	
Dislikes 0	
Response	

Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	

Seminole endorses the comments submitted on this Project by JEA.

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the 36-month assessment period.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
However, the implementation plan should clearly apply to the "raise-the-bar" portions of the revision.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	

Comment	
The implementation period and associated implementation plan are hard to follow. This is an industry wide issue, not just directed this standard. Suggested change would be to put actual dates in place of relate dates identified before the standard is approved. We have no problem with the 36 months as listed.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	
Agreed	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Agreement to the implementation period does not convey agreement with the content of the proposed changes to the standard.	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Texas RE requests the SDT provide technical basis supporting a 36 month implementation period.	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
BPA does not support the requirement for Corrective Action Plans in 4.6, BPA believes it is not economically justifiable to require Corrective Action Plans for low probability extreme events like these. Instead, an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system. If Corrective Action Plans are going to be required, BPA agrees that the 60-month implementation plan is appropriate.	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
TVA agrees with having 60 months for the development of the corrective action plan. However, we do not agree that a corrective action plan should be required for Requirement 4, Part 4.6.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	

Comment	
The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. We agree that for the Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 events, the system still needs to perform reliably and without any planning criteria violation. However, no operational workaround can be performed for any newly identified violation due to this suggested/clarified language for Footnote 13 and capital improvement projects will be the “only” corrective action plans which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/ implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction effort spanning 10-20 years. Hence a mere 60 months (5 years) for meeting Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 implementation and compliance is not adequate. The industry needs to be surveyed again to see the outcome from the studies with the modified/clarified language in 5 years (after 36 months for TPL-001-5 effective date + 24 months to develop corrective action plan) to have a more realistic implementation schedule for the remedies (Corrective Action Plans) for Part 2.7. **Suggestion**: Requirement 4, Part 4.6 is not needed since Requirement R4, Part 4.5 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey will be needed to determine a reasonable and appropriate timeline to implement the Corrective Action Plans just for the newly identified shortcomings for P5 events with the proposed/modified Footnote 13.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
We (utilities) probably already know that we cannot meet the 60 month implementation period. Capital improvements can not be determined and implemented in a 60 month time period. Forced compliance to 60 months would require undesirable mitigations such as system protection adjustments that	

might reduce system security, misoperations due to changes in protection systems that result in non-standard configurations and changes to maintenance practices due to non-standard application of protection systems.

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from “failure of a non-redundant component of a Protection System” event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting fromorm single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	No
Document Name	

Comment

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from “failure of a non-redundant component of a Protection System” event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting form single points of failure. In other words, the timing requirement of

the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
The scale of the Corrective Action Plans is unknown, and the coordination of capital projects may require a longer duration to effectively manage outage risks with other planned projects could exceed 60 months.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
SCL disagrees with the proposed requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	

Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. Recomment removing Requirement 4 Part 4.6 since Part 4.5 already addressesit.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	
Developing a mitigation plan and getting it in-service can be very challenging for utilities based on their budgetary requirements.	
Likes 0	
Dislikes 0	

Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
We believe that a phased approach should be taken to address the concerns for single point of failure. We do not believe that all transmission facilities are of equal value or pose an equal risk to the system. We believe that the risk is generally related to system voltage, and the highest voltage facilities need to be addressed first. Further, we recognize that there are many more lower voltage facilities with non-redundant protection systems that need to be addressed, and these upgrades will likely require the expansion or addition of control buildings to house the additional protection system components.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
See response to question 6.	
Likes 0	
Dislikes 0	
Response	

Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
a 60 month time frame may not be achievable depending on the scope of issues discovered. PG&E recommends that this be determined by the Transmission Owner in coordination with the Transmisison Planner and Planning Coordinator, or 120 months.	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is. We agree that for the Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 events, the system still needs to perform reliably and without any planning criteria violation. However, no operational workaround can be performed for any newly identified violation due to this suggested/clarified language for Footnote 13 and capital improvement projects will be the “only” corrective action plans which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/ implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction effort spanning 10-20 years. Hence a mere 60 months (5 years) for meeting Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 implementation and compliance is not adequate. The industry needs to be surveyed again to see the outcome from the studies with the modified/clarified language in 5 years (after 36 months for TPL-001-5 effective date + 24 months to develop corrective action plan) to have a more realistic implementation schedule for the remedies (Corrective Action Plans) for Part 2.7.	

Suggestion: Requirement 4, Part 4.6 is not needed since Requirement R4, Part 4.5 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey will be needed to determine a reasonable and appropriate timeline to implement the Corrective Action Plans just for the newly identified shortcomings for P5 events with the proposed/modified Footnote 13.	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
<span style="font-family: calibri,sans-serif; font-size: 12pt; mso-ascii-theme-font: minor-latin; mso-ansi-language: EN-US;" mso-hansi-theme-font:minor-latin"="" mso-fareast-language:en-us;="" roman";="" new="" mso-fareast-font-family:"times="" mso-bidi-language:ar-sa;="" times="">SMUD does not agree with the need for Part 4.6, as such cannot agree with an implementation plan for this requirement. SMUD does agree with the 60-month implementation date for the other requirements listed.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	

Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
As stated in question 6, the minimum time for implementation should be 60 months to account for existing plans and budgets. This should be an additional 24-36 months beyond the implementation period for the other requirements. Therefore, the implementation period should be between 84 and 96 months at a minimum.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Comments: Requirement 4, part 4.6, should be deleted. This new requirement goes way beyond	

what was recommended by Order No. 754 and has the possibility to cause undue financial burden to industry without a corresponding benefit to reliability. With regards to Requirement 2, Part 2.7, 60 months for implementation is not sufficient. The possibility of large capital expenditure due to Corrective Action Plans as well as the associated construction timelines makes a 60 month implementation difficult to comply with. A suggestion would be to perform a survey to see what corrective action plans are required after industry has had time to do evaluations and then establish an implementaion timeline.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Yes. As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Agreement to the implementation period does not convey agreement with the content of the proposed changes to the standard.	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	
Agreed.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
The implementation period and associated implementation plan are hard to follow. This is an industry wide issue, not just directed this standard. Suggested change would be to put actual dates in place of relate dates identified before the standard is approved. We have no problem with the 60 months as listed.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	

Answer	Yes
Document Name	
Comment	
However, the implementation plan should clearly apply to the "raise-the-bar" portions of the revision.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
KCP&L agrees with the “60-month” implementation plan; however, suggests adding language to clarify what the “60-month” period represents. The question implies there is a distinction in the implementation periods for specific Requirements, allowing 60-months for some and something different for other Requirements. We only can guess that the referenced 60-month period reflects the sum of the 36-month assessment period and the 24-month CAP development period. If that is the case, we suggest not using “60-months” and list the allocated implementation periods for each action—assessments, CAP drafting.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	

Answer	Yes
Document Name	
Comment	
SNPD does not have simulated events that may cause cascading outages. However, to support the regional and RC efforts with controlling any observable IROL or identified potential IROL events within the WECC region, SNPD shall follow the RC and PC accepted and approved guidelines.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	
Document Name	
Comment	
Unsure. Some implementation may be longer.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE requests the SDT provide technical basis supporting a 60 month implementation period.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	
Document Name	
Comment	
AECI disagrees with the proposed requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	

Comment	
Are corrective action plans required to be developed within 60 months or to be completed within 60 months? Assuming the TP/PC takes most of the 36 months to implement the rest of TPL-001-5, the additional 24 months provides very little time for a TO/GO to actually implement construction projects.	
Likes 0	
Dislikes 0	
Response	

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	

Answer	No
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jameson Thornton - Pacific Gas and Electric Company - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	

Answer	Yes
Document Name	
Comment	
: Due to the changes incorporated in this proposed TPL standard, Reliability Standard **CIP-014-2 – Physical Security** can be impacted with the outcome. The proposed TPL-001-5 is setting the bar higher than before for the PCs and TPs. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PCs and TPs (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with TPL-001-5 analyses.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
While there are no specific documents that stand out as being in conflict with the proposed changes, Peak believes that the notion of separation of responsibilities might be compromised with the proposed changes, specifically, responsibilities between the RC and the PC/TP. Perhaps, in this regard, the proposed changes might conflict with the NERC Functional Model. Some of the proposed revisions might be interpreted to pull RCs into the work for which PCs and TPs are responsible, thus implicitly requiring the RCs to perform duties they otherwise would not perform. While on the surface the proposed revisions may appear to be a good idea to improve communications between operations and planning, Peak believes that there are better ways of achieving that objective without creating implied responsibilities for the RC in the planning horizon, where the RC has no direct responsibility. Peak would support revisions to the requirements that do not create implied responsibilities for the RC in the planning horizon.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
The proposed changes to sub-requirement 1.1.2 may be in conflict with the standard IRO-017-Outage Coordination, since outage coordination is more of an Operational Planning issue (next day studies up to six months) than a Transmission Planning issue, which covers one to ten year planning horizon.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
MH believes that the SDT was unable to capture the proposed recommendations in the background document prepared by NERC SPCS and SAMS. A risk based assessment should be used to identify locations of concern rather than making full protection redundancy a bright line requirement. The background document provided a criteria for busses to be evaluated (Table 1.1) and criteria to evaluate the system performance (Table 1.2).	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	

Answer	Yes
Document Name	
Comment	
Due to the changes incorporated in this proposed TPL standard, Reliability Standard **CIP-014-2 – Physical Security** can be impacted with the outcome. The proposed TPL-001-5 is setting the bar higher than before for the PCs and TPs. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PCs and TPs (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with TPL-001-5 analyses.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
As previously mentioned in these comments, we noted possible inconsistencies with the following documents: - NERC Glossary definition of "Protection System" - ERO Enterprise-Endorsed Implementation Guidance for TPL-001-4	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No

Document Name	
Comment	
No. See Question 4.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that past performance can be a good indicator of future performance. These types of outages have not been an issue in the past. BPA believes that it is not economically justifiable to require corrective action plans for low probability extreme events like these. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered, if studies indicate there is the potential for cascading on critical parts of the system. BPA believes the penalties are too severe for such low probability extreme events.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	No
Document Name	Table C.png
Comment	

The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. **Suggestion**: Since Requirement 4, Part 4.6 is not needed, no corresponding VRF/VSL revised language is needed.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	
Corrective Action Plans as detailed in Part 2.7 do not explicitly allow for use of Asset Management principals to manage the risk of the likelihood and consequence of an outage.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

SCL disagrees with the proposed requirements above, and therefore disagrees with the proposed changes to align requirement 4.6 with requirement 2.7.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Comments: The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4 Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. No corresponding VRF/VSL is needed since this requirement should be removed.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Consistent with our response to Question 4, developing corrective action plans to include redundant relaying for extreme events is inconsistent compared with the existing TPL-001-4 requirements.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	No
Document Name	
Comment	
Please refer to Question 4 comments.	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
(1) We believe the development a Corrective Action Plan is administrative in nature and constitutes a Lower Violation Risk Factor in the Long-Term Planning Horizon. The proposed requirement to develop a Corrective Action Plan does not have a direct or adverse effect on the electrical state or capability of the BES and does not align with the Medium Violation Risk Factor criteria identified by NERC.	

(2) NERC identifies the criteria for a High VSL as the "performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent." In comparison, NERC identifies the criteria for a Lower VSL as the "performance or product measured almost meets the full intent of the requirement." We propose moving the failure to develop a Corrective Action Plan to the Lower VSL, as the full intent of Requirement R4 focuses more on the performance of Contingency analyses.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The Violation Risk Factor (VRF) and Violation Severity Level (VSL) for Requirement 4, Part 4.6 emphasizes a new level of depth for a Corrective Action Plan in the Stability portion of the Planning Assessment. This seems inconsistent with the VRF/VSLs for Requirement 2, Part 2.7 which focus on creating a Corrective Action Plan for a number of actions already implemented by industry standards. See comments #3 and #4.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

The new language under Requirement R4, Part 4.6 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.5 already addresses this cascading issue for extreme events in the currently enforceable TPL-001-4 standard and should be left as-is. Suggestion: Since Requirement 4, Part 4.6 is not needed, no corresponding VRF/VSL revised language is needed.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	No
Document Name	
Comment	
For clarification, Part 4.6 is just for developing and not completing a CAP?	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	

No, see comments about modifying 4.5 instead of 4.6. The VSL for 4.5 should remain "Lower". Requirements to eliminate non-redundant relay designs should be defined in PRC standards.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI disagrees with the proposed changes to Requirement 4, Part 4.6, and therefore disagrees with the revisions to the VRF/VSLs.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
R4 4.6 should be deleted entirely for reasons noted above	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
see attached file in question 1	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC does not comment on VRF/VSLs.	
Likes 0	
Dislikes 0	

Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
It should not result in a CAP entry and therefore would require no change	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

10. Do you have any other general recommendations / considerations for the drafting team?	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
No further comments at this time.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
These comments were submitted on behalf of Dawn Quick at NIPSCO dquick@nisource.com	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI & Member G&Ts

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Shaw - Lower Colorado River Authority - 1,5,6, Group Name LCRA Compliance

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2 - NPCC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Oliver Burke - Entergy - Entergy Services, Inc. - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deborah VanDeventer - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6, Group Name PGE - Group 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Powell - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC,RF, Group Name PPL - Louisville Gas and Electric Co.	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - United Illuminating Co. - 1,3 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 1,3,4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1,4,5	
Answer	Yes
Document Name	
Comment	
Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or Year Two, and Year Five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to require analysis as a Standard Requirement of Transmission Planning such as TPL-001. Anything less than 1-year belongs to the Operations timeframe.	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	
Comment	
The modified verbiage for Part 2.1.3 includes the phrase “as selected in consultation with the Reliability Coordinator” – this modification is unnecessary and causes confusion. It is not clear why Part 2.1.3 needs to be modified at all. Further, including this phrase in Part 2.1.3 makes it inconsistent with the verbiage in Part 2.4.3 If the standard is calling for PC/TP consultations with other functional entities (RC), applicability of the TPL-001-5 standard should also apply to those other entities so those entities have a vested interest in collaborating with the PC/TP. Otherwise the other entities have no obligation to participate. Finally, NERC should undertake a complete refurbishment of the standard, with NERC holding technical discussions in an open forum to address all the ambiguities presently left to interpretation.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Florida Municipal Power Agency - 3,4,5 - FRCC

Answer	Yes
Document Name	
Comment	
1) Both additions in the stability analysis section (R2.4.3 and R2.4.5) need to reference or somehow incorporate R4.4 and the ability of the PC or TP to identify and simulate only those events that are expected to produce the most severe System Impacts. This allows the PC and TP to maintain some semblance of engineering judgment and avoid conducting an un-bounded number of simulations. 2) The drafting needs to correct the cross reference from R2.7 to R2 part 2.4.3 as the proposed revisions re-number 2.4.3 to 2.4.4.	

Thank you again for the efforts of the SDT and we appreciate the opportunity to provide comment. We hope the comments are found to be helpful.	
Likes 0	
Dislikes 0	
Response	
Ben Li - Independent Electricity System Operator - 2 - NPCC, Group Name ISO/RTO Council Standards Review Committee	
Answer	Yes
Document Name	
Comment	
In Part 1.2 of section C on page 16, the new language identifying the Measures for which the responsible entity must retain evidence of compliance appears to incorrectly exclude Measure M8. Further, the corresponding changes to IRO-017 relative to R 1.1.2 as recommended in the PC report to the drafting team (excerpt below) should also be pursued: • Use the coordination process developed pursuant to IRO-017-1 Requirement R1 to direct how ALL known scheduled outages are reviewed and the actions that must be taken. The following objectives should be added to R1: · Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into the Near Term Assessment of the Planning Horizon required by TPL-001-4, and whether and which of these known scheduled outages will be studied in this Assessment. · Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Michael Haff - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes

Document Name	
Comment	
Seminole endorses the comments submitted on this Project by JEA.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Great Plains Energy - Kansas City Power and Light Co. - 1,3,5,6 - SPP RE	
Answer	Yes
Document Name	
Comment	
We have a question: The proposed implementation plan makes reference to, in certain circumstances, carrying over from TPL-001-4 the 84-month exception (our word) period related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service. We are unclear how the 84-month exception will impact, correlate or align with TPL-001-5's proposed 36-month assessment period and the 24-month CAP drafting period?	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes

Document Name	
Comment	

In regards to Requirement 5:

There is academic and industry documentation used to define what is “acceptable” related to steady state voltage limits and transient voltage response. The documentation demonstrates negative impact to the transmission system and/or electrical equipment as result of transient voltage remaining below a certain threshold for a certain time-frame, as well as for steady state voltage being either too high or too low.

Georgia Transmission Corporation has not found any academic or industry documentation that suggests that there is a negative impact to either the transmission system or electrical equipment related to steady state voltage deviation.

There is a lack of information to document that steady state post-Contingency deviation (the difference between pre-Contingency steady voltage and post-Contingency steady state voltage) beyond a certain limit has a negative impact on either the transmission system or electrical equipment. Consequently, Transmission Planners and Planning Coordinators will be required to develop a Corrective Action Plan to address system conditions that fall outside of voltage deviation criteria that have no real impact on system reliability. Therefore this voltage deviation criteria should be eliminated.

Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	Yes
Document Name	
Comment	

We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5 and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request.

The criteria for buses to be tested (Table A; reproduced below) under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. However, the assessment according to the proposed TPL-001-5 requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. Due to this more in-depth analyses now required, there will definitely be a significant new findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure (Table C; reproduced below) under data request. Before the industry assesses the entire BES (implementation plan: 36 months) followed by the development of the Corrective Action Plans just for P5 events with the proposed Footnote 13 (implementation plan: additional 24 months); it will be very pre-mature at this time to grant 60 months for the Corrective Action Plan implementation. It will be logical to have another survey/data request performed after 60 months from the initial implementation of the proposed standard (36 months analyses + 24 months Corrective Action Plan development). Then, depending upon the outcome, a more realistic implementation plan for the Corrective Action Plans can be developed. The Corrective Action Plan for the extreme events Requirement R4, Part 4.6 should be completely removed; along with the corresponding VRF/VSL languages; from the proposed standard as this is already addressed by the Commission approved TPL-001-4 Requirement R4, Part 4.5.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Allow planning engineer(s) flexibility in their annual planning assessment pertaining to operational and system protection studies. Avoid “in consultation with the Realiability Coordinator” language.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team develop language for section 2.4.3 that is consistent with section 2.1.3.	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 1,3,5,6

Answer	Yes
Document Name	
Comment	
Reliability Standard IRO-017-1 R3 requires each PC and TP to provide its Planning Assessment to impacted RCs. To better consolidate related requirements, recommend adding the RC as a recipient of the Planning Assessment in TPL-001.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes

Document Name	
Comment	
Duke Energy recommends that when providing addiotional clarity/rationale on the subject of redundancy, the drafting team consider referring to a technical paper developed by the System Protection Control Task Force developed in 2008 titled: “Protection System Reliabilty: Redundancy of Protection System Elements”. Some aspects of this document may be helpful in providing additional clarity on this topic for the industry.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
(1) The Standards Authorization Request associated with this project provided the SDT an opportunity to evaluate requirement retirements under Paragraph 81 criteria. We believe Requirements R5, R6, R7, and R8 fall under such criteria. Documenting acceptable voltage limits and deviations and defining instability criteria for Cascading and uncontrolled islanding events are all necessary, yet are likely documented as assumptions and technical rationales listed within Planning Assessments. Moreover, these criteria are not directly associated with the required execution of conducting studies. The identification of study coordination roles and responsibilities through meeting minutes and distribution of Planning Assessment results to appropriate entities within a specific time period are administrative activities. Further proof is that these requirements do not have performance-based VSLs identified, particularly R8 which doesn’t even have a VSL identified at all. (2) The proposed Evidence Retention period identified within the standard does not identify Measure M8. (3) We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	
Comment	
In Part 1.2 of section C on page 16, the new language identifying the Measures for which the responsible entity must retain evidence of compliance appears to incorrectly exclude Measure M8. This appears to be a typo.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Berkshire Hathaway - NV Energy - 6 - WECC

Answer	Yes
Document Name	
Comment	
Similar to the comments provided in Question 2 for Requirement 2, Part 2.4.5, NVE has concerns about possible resource issues for performing a dynamic analysis for all P1 events. NVE feels that the transmission planners should continue to use their engineering judgment and discretion to select which contingencies make the most sense to study for their system for the dynamic analysis.	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1

Answer	Yes
Document Name	
Comment	

The comment form did not ask of entities agreed with the proposed changes to requirement R2.1.3, so Peak is providing those comments here. Peak does not agree with the proposed revisions in requirement R2.1.3. The proposed revision states, *"[Qualifying studies need to include the following conditions:] R2.1.3. P1 events in Table 1, **as selected in consultation with the as directed Reliability Coordinator**, with known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled."* Peak disagrees with this proposed revision for many of the same reasons we disagree with the proposed changes to requirement R1.1.2. Overall, both proposals involve the RC in matters that are outside the RC's timeframe of assessment responsibility.

Additionally, the proposed requirement R2.1.3 is confusing to Peak. Is this standard requiring the RC to be consulted to determine ***which*** single P1 Contingencies the PC/TP needs to include in their studies? It is unclear to Peak exactly what the proposed changes to this requirement is trying to accomplish.

Peak as an RC requires operations reliability for ***all*** P1 Contingency events…not just ***certain*** ones. Involving the RC in the selection of P1 Contingencies that a given PC/TP should include in their studies is burdensome for RCs and does not provide any tangible reliability benefit. This proposed requirement creates an implied expectation for the RC to have already performed some kind of screening of P1 events and for the RC to relay any critical P1 performance related issues to the PC/TPs as part of the proposed consultation. Peak believes that this kind of analysis is above and beyond the expectations for RCs today, and that the standard should in no way create such an implied responsibility for RCs. Peak believes that identifying the P1 Contingencies that should be included in a PC/TP's Planning Assessment is purely a PC/TP responsibility and should not involve RCs explicitly in the standard.

By default, proposed requirement R2.1.3 requires the RC to do something in order for the TP/PC to be compliant – which in effect is a requirement for the RC. Peak believes this is not a good approach for writing standards. If the RC does not participate in this consultation, or if the consultation is "weak", is the PC/TP faced with a potential compliance ramifications? If such is the case, is the RC subject to any compliance ramifications?

Additionally, given the high number of PCs and TPs in the Western Interconnection, it is impractical for the Peak as an RC to have a prominent role in the determination of the P1 Contingencies a given PC/TP should include in their studies.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no ISO-NE, NYISO and NextEra	
Answer	Yes
Document Name	
Comment	

Requirement 2 – 2.7.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS).

Requirement 4 – 4.1.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS).

Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001.

Outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning

time horizon. Using a bright-line of 12-months to determine the applicability of IRO-017 vs TPL-001 gives clarity and certainty of the appropriate requirements to be met.

Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	

We recommend including in the standard, as an attachment, guidelines and examples that provide clarity for footnote 13. This will allow the industry to have a consistent approach when the P5 planning events and Extreme events are evaluated.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Berkshire Hathaway - PacifiCorp - 6 - WECC	
Answer	Yes
Document Name	
Comment	
Please refer to comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Comments: We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5	

and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request. The criteria for buses to be tested under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. The proposed TPL-001-5 language requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. This will increase the findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure in Table C of the data request.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
When analyzing single-point-of-failure contingencies for protection schemes under three-phase faults as extreme events, it is important to note that a particular scheme could be fully redundant for three-phase faults whereas it is not redundant for single-phase-to-ground faults. For example, when three-phase faults are considered, there will be three current transformers involved and perhaps three relay units involved (particularly for lines protected by electromechanical relay units, which are often single-phase units), and if these components are the only sources of non-redundancy for a P5 contingency evaluated for a single-phase-to-ground fault, the scheme may not be applicable to single-point-of-failure for evaluating three-phase faults as an extreme event. The wording of the standard should ensure that this distinction can be made.	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1	
Answer	Yes

Document Name	
Comment	
ATC notes that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
1. Define SPF "single point of failure" at the first time occurance in "Rationale for Requirement R4 Part 4,6" , page 11 of 38 in the Redline version. 2. It looks like the last sentence of Requirement R4.5 "If the analysis concludes there is Cascading caused by ………" looks redundant after introducing requirement R4.6.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
WAPA believes there is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system. Frequency of these SPF events are so seldom, they do not warrant the cost to eliminate unless there are significant risks to the transmission system such as instability and cascading. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1,3 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Refer to comments for Question 1.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	

Comment	
Corn Belt agrees with the NSRF concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5. Since NERC Protection Systems are referenced, the NSRF recommended that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section: From PRC-005-6: 4.2.6 Protection Systems and Sudden Pressure Relaying for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition: 4.2.6.1 Protection Systems and Sudden Pressure Relaying for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100kV or above. Also noted that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
John Babik - JEA - 1,3,5	
Answer	Yes
Document Name	Table A.png
Comment	
We agree that the data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The added/clarified language in the draft TPL-001-5 for P5 and stability performance extreme events 2e-2h along with footnote 13 will, however, require the PCs and TPs to perform a lot more analyses than was originally performed for Order No. 754 data request.	

The criteria for buses to be tested (Table A; See Enclosed) under Order No. 754 data request required 4 or more circuits at 200 kV or higher, and, 6 or more circuits between 100 kV to 200 kV. However, the assessment according to the proposed TPL-001-5 requires ALL BES buses; regardless of how many circuits terminate at each BES bus; to be tested. Due to this more in-depth analyses now required, there will definitely be a significant new findings for P5 Planning events for which the performance requirement is more restrictive than the performance measure (Table C; See Enclosed) under data request. Before the industry assesses the entire BES (implementation plan: 36 months) followed by the development of the Corrective Action Plans just for P5 events with the proposed Footnote 13 (implementation plan: additional 24 months); it will be very pre-mature at this time to grant 60 months for the Corrective Action Plan implementation. It will be logical to have another survey/data request performed after 60 months from the initial implementation of the proposed standard (36 months analyses + 24 months Corrective Action Plan development). Then, depending upon the outcome, a more realistic implementation plan for the Corrective Action Plans can be developed. The Corrective Action Plan for the extreme events Requirement R4, Part 4.6 should be completely removed; along with the corresponding VRF/VSL languages; from the proposed standard as this is already addressed by the Commission approved TPL-001-4 Requirement R4, Part 4.5.	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
The corresponding changes to IRO-017 relative to R 1.1.2 as recommended in the PC report to the drafting team should also be pursued.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

BPA believes the drafting team should consider the economical impact of requiring Corrective Action Plans for low probability extreme events, especially if the type of events have not occurred in the past or are not known to cause severe consequences.

BPA has suggested edits to the requirement language for the following:

R1.1.2. Known outage(s) of generation or Transmission Facility(ies) as selected in consultation with its Transmission Operator for outage durations that occur in the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3

R2.1.3. P1 events in Table 1, as selected in consultation with its Transmission Operator, with the known outages modeled as specified in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

R4.6. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R4.6.1 and **R4.6.2** deleted.

Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 1,3,5	
Answer	Yes
Document Name	
Comment	

The SDT should consider changing the purpose statement of TPL-001 (section A.3). It identifies the wrong goal. The "Purpose" of the requirement is not to establish a requirement. The purpose of the requirement is to ensure that the Bulk Electric System will have the resources necessary to meet system load while also meeting performance requirements. This is done by requiring the TP/PC to assess the future (forecasted) system needs of its portion of the Bulk Electric System using software tools.

The SDT should consider limitations on available data, the capabilities of analysis software (power flow, dynamics and short circuit) and the burden placed on the TP/PC. (More paperwork does not translate into better reliability).

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The NSRF has concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5.

Since NERC Protection Systems are referenced, the NSRF recommends that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section:

From PRC-005-6:

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

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

The NSRF notes that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Order 786 specifically mentions that TPL-001 is intended to analyze the Near-Term Transmission Planning Horizon and requires annual assessments using Year One or year two, and year five. We agree that 1-, 2-, and 5-year forward looking is the appropriate and intended timeframe to be evaluated by the requirements of TPL-001. Therefore, only outages planned for this timeframe (more than 12-months forward) are appropriate to be required to be analyzed as a requirement of a Transmission Planning standard such as TPL-001. Outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon. Using a bright-line of 12-months to determine the applicability of IRO-017 vs TPL-001 gives clarity and certainty of the appropriate requirements to be met.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Requirement 2 – 2.7.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS). Requirement 4 – 4.1.1: the reference to Special Protection Systems (SPS) should be replaced by Remedial Action Schemes (RAS).	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We recommend including in the standard, as an attachment, some guidelines and examples that clarify the type of protection failures that need to be studied. This will allow the industry to have a consistent approach when the P5 planning events and extreme events are evaluated.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Although it is not specified as part of the scope if this project, Texas RE is concerned the standard does not require studying unknown outages in off-peak conditions in addition to the known outages. Studying all conditions, known and unknown, addresses the “planned maintenance outages of significant facilities” in FERC order 786, paragraph 40. Even routine maintenance outages that occur during off-peak load conditions could be significant, but TPs and PCs may not have the information needed to meet the “known” requirement when TPL studies are being performed.

Likes 0	
Dislikes 0	

Response

John Merrell – Tacoma Public Utilities (Tacoma, WA) - 3	
Answer	Yes
Document Name	
Comment	
1. Footnote 13.4 has numerical issues. As explained above, Tacoma Power would prefer explicit requirements for each of the 5 bullet points in the Protection System Definition. If 13.4 is kept, it should be revised to say “A single control circuitry path associated with protective functions between the DC panel and a trip coil of the circuit breakers or other interrupting devices.” In the current draft, it is unclear whether there is a requirement to have dual trip coils. 2. The combination of a P1 event in Table 1 and known outages modeled as in Requirement R1, Part 1.1.2 is not a single contingency. Thus, the system performance requirement should be less stringent than for a P1 event. For these types of events, interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed.	
Likes 0	
Dislikes 0	
Response	

Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

Do not use this form for submitting comments. Use the electronic form to submit comments on **TPL-001-5 – Transmission System Planning Performance Requirements** . The electronic form must be submitted by **8 p.m. Eastern, Wednesday, May 24, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

   ☐ Yes
   ☒ No

   Comments:
   Corn Belt agrees with the SPP Standards Review Group and its clarification of an important issue regarding the expectations of regulatory staff on the impacts of Requirement 1, Part 1.1.2. The clarification is about the differences in power flow case topologies used by SPP Operations and SPP Planning. Issues found in the operating horizon would be specific to that point in time and would take into consideration any planned outages, forced outages, generation dispatch, transfers, and load levels that would cause concerns. These operating horizon variables would be changing from minute to hour to day to week to month to season to year. The same outage placed in a planning horizon assessment would be placed into a model that has a lot fewer outages, different generation dispatch, different transfer levels, and different load levels. The topology differences between the two power flow models is significant enough that the operation horizon outages would more than likely not cause issues in the Transmission System Planning Performance Requirements (TPL) Assessment. Further, the SPP Standards Review Group states that trying to mimic, follow, or forecast these operating horizon outages in a meaningful manner would be a moving target. This is due to the fact that most of the planned outages are due to maintenance and capital projects that usually do not re-occur within a 3-5 year period, if ever. The SPP Standards Review Group also found the proposed language to be vague and ambiguous, regarding the timeframe, and therefore would be hard to defend during an audit.

   Corn Belt agrees with the SPP Standards Review Group that the language is unclear as to whether outages should be evaluated only in the season for which they are planned or whether they should be evaluated for the peak or off-peak 1 or 2, and 5 planning horizon. In addition, the reference to the number of additional cases and the associated seasons that could be required. Corn Belt agrees with the SPP Standards Review Group suggested proposed language that would tie this process to the TOP Standards instead of the TPL Standards as this is pertaining more to operation related issues.

   Also concerned that this could significantly increase the number of near term cases created and studied and add significant work load to tune L&R for these cases. Concern this will significantly increase PC/TP study work load without benefit due to undetermentant amount of outages that need studied. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. Concern this change will result in significant wasted time and effort to produce results that won't ultimately be used because the same outages will be restudied in ops horizon.

Firmly disagree with the bullet in the Rationale for Requirement R1 Part 1.1.2. "Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);" Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word "limited" in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a "small number of" outages. If the intent is for the PC/TP's to study only a limited amount of outages (beyond those already studies as P3 and P6's) then edit the language to state so.

Outages of concern to be studied separately. Base case assumptions.[A1]

Suggested Language:[A2]
R1.1.2 Known critical 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.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

☒ Yes
☐ No

Comments: : Corn Belt agrees, but suggests that "more than 1 year" be substituted for long lead time throughout TPL-001-5 where appropriate for better clarity.

Concerns that the number of additional dynamic analyses to include long lead time items taking more than 1 year for P1 and P2 needs to be bounded. There are real computational constraints that could take months to run. An example could give the Transmission Planner discretion to chose the worst conditions.

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

☐ Yes
☒ No

Comments:

Recommend that “Cascading” be replaced with a specific MW number such as the loss of 2,000 MW of generation as referenced in the EOP-004 standard. The term “Cascading” remains too vague and subject to change. A MW threshold is a better “bright line” criteria.

Recommend each BES Protection System component class be covered explicitly in Footnote 13 along with an inclusion or exclusion justification. Abrief Protection System scope for Footnote 13 may also be helpful.

Ask if relays should be limited to electromechanical relays as the SPCS/SAMS Order 754 report identified risk depends upon the relay type and protection system design
(meaning multiple relays to respond to a fault). If an entity shows no electromechanical primary or aux relays can that be sufficient to exclude from being redundant?

Ask if communications systems should be eliminated except for RAS. The SPCS/SAMS Order 754 report identified communications systems posed a lower risk level.

Example NERC Defined Protection System Component Classes, Scope and Applicability:

NERC Bulk Electric System (BES) protective relays/sudden pressure relays/reclosing relays:
NERC BES PRC-005-6 Protection System electromechanical primary and auxillary relays are included in footnote 13. This includes PRC-005-6 identified sudden pressure and reclosing relays.

NERC BES associated communication systems:
NERC BES PRC-005-6 associated communication systems are included in footnote 13.
Redundant communications system for footnote 13 would be two communications channels. Redundant communications for Footnote 13 does not require separate and diversely routed communications towers.

NERC BES Voltage and current sensing devices:

NERC BES PRC-005-6 voltage and current sensing devices are not included in footnote 13. The SPCS/SAMS Order 754 report identified that voltage and current sensing devices were robust and posed a lower risk level.

NERC BES Station batteries:

NERC BES PRC-005-6 Station batteries are included in footnote 13 with the following exceptions. A single station DC supply is allowed if monitored for low voltage and open
circuit alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES Battery Chargers:
NERC BES PRC-005-6 station battery chargers are included in footnote 13. A single station charger is allowed if the battery bank is monitored for low voltage and open circuit
alarms to a centrally monitored location within 24 hours of abnormal condition detection.

NERC BES DC control circuitry:
NERC BES PRC-005-6 DC control circuitry is included in footnote 13 but its outcome is already considered in the P4 stuck breaker category. Whether stuck breaker of a DC control circuit failure, the end result is the same.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

   ☐ Yes
   ☒ No

   Comments:
   The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report. This report recommended the following:

   Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads “[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2.”

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] 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

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
  - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*

   - *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*
- *Keep as an extreme event with no change (other than footnote 13)*
   - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a "subset of Table 1 Extreme Events" be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because "the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event". Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although Corn Belt strongly disagrees with requiring a Corrective Action Plan for this "subset of Table 1 extreme events", if this requirement is carried forward Corn Belt recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (all events): 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 (P0 through P7 events 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 (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	3Ø	EHV, HV	Yes	Yes

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

☐ Yes
☒ No

Comments: Corn Belt agrees with the SPP Standards Review Group proposal that a standard applicable to the Reliability Coordinator (RC) address RC requirements should be considered. Potentially, it could be added to NERC Stanadard IRO-017.

Corn Belt agrees with the SPP Standards Review Group suggestion that the Transmission Owners (TOs) and Generator Owners (GOs) should be added to the applicability section of the standard and have requirements to respond to TP/PC requests for information to help the PC/TP develop Corretive Action Plans (CAPs).

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

☒ Yes
☐ No

Comments: As long as the implementation plan refers to the development of required CAPs, not the placing the required CAPs in service.

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

☐ Yes
☒ No

Comments:

We (utilities) probably already know that we cannot meet the 60 month implementation period. Capital improvements can not be determined and implemented in a 60 month time period. Forced compliance to 60 months would require undesirable mitigations such as system protection adjustments that might reduce system security, misoperations due to changes in protection systems that result in non-standard configurations and changes to maintenance practices due to non-standard application of protection systems.

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utlities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting from~~orm~~ single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

   ☐ Yes
   ☒ No

   Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

   ☒ Yes
   ☐ No

   Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments:
Corn Belt agrees with the NSRF concerns that the number of additional dynamic analyses for P1 and P2 needs to be bounded in some reasonable fashion for Requirement 2, Part 2.4.5.

Since NERC Protection Systems are referenced, the NSRF recommended that the same PRC-005-6 exclusions for individual wind and solar generators be added to the applicability section:

From PRC-005-6:

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

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

Also noted that the reliability impacts from actual extreme stability 2e-2h events are expected to be much less severe than the reliability impacts found in the FERC Order 754 analyses because the Order 754 analyses did not take into account the operation of bus tie breakers, which significantly reduce the extent of contingencies that involve bus sections.

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Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

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Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

   ☐ Yes
   ☒ No

   Comments: 1. IRO-017-1 already requires the RC to maintain a coordination process for the Near-Term Transmission Planning Horizon. The proposed approach in TPL provides little guidance to the RC/TP/PC as to what level of detail to model future outages. This may lead to widely varying practices across regions.

   2. We support the other approaches suggested by FERC to limit the scope based on both time and outage significance. The proposed alternate for R1.1.2 is:
   Schedule outage(s) of Generation or Transmission Facility(ies) that are identified by the Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and lasting longer than 90 days.

   3. It is important to note the difference between a planned outage in the sense: (1) that maintenance crews "plan" for insulation testing of every transformer every three years, and (2) that a nuclear plant plans to be offline for refueling from exactly 3/3/2019 @ 19:30 to 9/15/2019 08:00. In the former case, the exact outage dates are both unknown and highly flexible, whereas with the latter the outage has specific dates that can be modeled and it must occur regardless of system conditions. The previous 6 month limit served as a screen to identify only those outages which were likely to occur during critical system conditions. Most maintenance is scheduled to avoid system peaks.

   4. It unclear how to model planned outages in year one, year three or year four if the TPL planning assessment uses year two and year five.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

   ☐ Yes
   ☒ No

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

☐ Yes
☒ No

Comments:
1. Tacoma Power does not agree that all parts of the Protection System should be treated identically with regards to single point failures. As identified the order 754 final report, some protection system components such as protective relays, auxiliary relays, and DC circuits downstream of the DC panel branch circuit protection have been documented as common causes of actual single point failures. The final report also identifies that AC inputs and the station DC supply pose much lower risk of failure to trip. The attached table shows an alternative set of contingencies that would implement a more risk-based approach to single point failures of each kind of component in the protection system.

2. Tacoma Power proposes P5 include the more common kinds of failures of the protection system that include 1) Protective relays which respond to electrical quantities; 2) A single communications system, necessary for correct operation of protective functions, which is not monitored; and 3) Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

3. New P8 and P9 contingencies for EHV facilities would address the remaining less likely to fail components of the protection system including (1) Voltage and current sensing devices providing inputs to protective relays, (2) Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply). Since these kinds of components are less likely to fail, allowing interruption of firm transmission service and nonconsequential load should be allowed for all voltage levels.

The 754 report found that only 0.7% of 100-199 kV buses had adverse system response from a single point of failure whereas 20% of EHV buses had adverse system response from a single point of failure. This disparity indicates efforts mitigating single component failures should be focused on the EHV system. The new P8 and P9 (i.e. the proposed d-h extreme events) should apply to just EHV elements.

Creating new events P8 and P9 would clarify that Corrective Action Plans are required for these contingencies whereas extreme events do not require CAPs.

4. Tacoma Power supports reformatting of Table 1, as it is currently quite confusing.

5. There appears to be confusion as to whether to monitor protection circuits, the battery bank or the main DC breaker for open circuit. Trip coil monitoring does not provide any assurance the batteries are connected. Furthermore, there appears to be a lack of publicly available evidence

that battery open circuit monitoring substantially lowers the risk of the protection system failing to trip. Dual batteries may be more appropriate for many EHV applications.

6. Battery monitoring system cost roughly the same amount as the set of batteries they monitor. Imposing additional costs for battery monitoring systems may lead to utilities replacing battery banks less often.

7. If the SDT continues to include monitoring as a viable option, these additional clarifications are need: (1) battery open circuit monitoring is required, (2) every breaker/fuse in the DC system must be monitored if it is a single point of failure, (3) a single trip coil is a single point of failure and is not mitigated by having trip coil monitoring unless there is independent breaker failure control circuitry, (4) low voltage monitoring threshold for battery voltage shall be coordinated with the battery design to give indication with at least 50% of battery capacity remaining, (5) auxiliary type relays for loss of DC may not be sufficient for low voltage monitoring of the battery, although they may be used for monitoring for loss of DC, and (6) non-battery-based DC systems require redundancy and should be addressed in a separate bullet under Footnote 13.

8. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6.

9. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

☐ Yes
☒ No

Comments: Tacoma Power disagrees with the concept of requiring CAPs for extreme events. If events are critical enough to need a CAP, they should be listed as required contingencies. Please see our comments to question 2 with regard to which events at which voltage levels should have CAPs.

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

☒ Yes
☐ No

Comments: Tacoma Power agrees with the drafting team, provided that the Reliability Coordinator's role under Requirement R1, Part 1.1.2, is only advisory.

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

☐ Yes
☐ No

Comments:

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

☐ Yes
☒ No

Comments: Are corrective action plans required to be developed within 60 months or to be completed within 60 months? Assuming the TP/PC takes most of the 36 months to implement the rest of TPL-001-5, the additional 24 months provides very little time for a TO/GO to actually implement construction projects.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☒ No

Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

☐ Yes
☐ No

Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments: 1. Footnote 13.4 has numerical issues. As explained above, Tacoma Power would prefer explicit requirements for each of the 5 bullet points in the Protection System Definition. If 13.4 is kept, it should be revised to say “A single control circuitry path associated with protective functions between the DC panel and a trip coil of the circuit breakers or other interrupting devices.” In the current draft, it is unclear whether there is a requirement to have dual trip coils.

2. The combination of a P1 event in Table 1 and known outages modeled as in Requirement R1, Part 1.1.2 is not a single contingency. Thus, the system performance requirement should be less stringent than for a P1 event. For these types of events, interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed.

Unofficial Comment Form

Project 2015-10 Single Points of Failure
TPL-001-5

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Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

☐ Yes
☒ No

Comments:

WAPA agrees with the intent to include significant impactful outages that are important to evaluate ahead of what is covered in the Operations Horizon, but we need to ensure that the language change to Requirement 1, Part 1.1.2 supports this intent. It is essential that the scope of outages be limited to significant planned outages that are not hypothetical in nature. Otherwise, there is a concern that this could significantly increase PC/TP study work without an appreciable benefit due to an undeterminant amount of outages that need to be studied. Outage scheduling changes could occur potentially leading to the results from the R1.1.2 analysis becoming irrelevant as it gets closer to when the outage will actually occur (Operations Horizon). These outages will need to be restudied in the Operations Horizon using more accurate information anyway. Even though the 6 month duration may not be perfect, it did provide specific criteria to select outages to study. There is a risk that the proposed language change to R1.1.2 could lead to it being left wide-open regarding what should be included in a Planning model because there are no parameters on what constitutes a significant planned outage.

WAPA disagrees with the bullet in the Rationale for Requirement R1 Part 1.1.2. “Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (see P 44);” Category P3 and P6 does sufficiently cover most maintenance outages any utility would expect and the criteria for R1.1.2 should define outages beyond those that are normaly studied as Category P3 and P6.

Futher, the word “limited” in the comment form Question 1 above is not in the proposed language of R1.1.2, and is misleading by implying the intent is for a “small number of” outages. If the intent is for the PC/TP’s to study only a limited amount of outages (beyond those already studies as P3 and P6’s) then edit the language to state so.

Suggested Language (add a qualifier to specify these outages should be critical/significant in nature and leave the ultimate decision upon what constitutes a significan planned outage to the PC/TP per R1 that, “shall maintain System models… to complete its Planning Assessment”):

R1.1.2 Known **critical** 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.

2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

   ☒ Yes
   ☐ No

   Comments:

3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

   ☐ Yes
   ☒ No

   Comments:

   WAPA agrees with the intent but offers improvements to the language.

   In Order No. 786 (P69), FERC declined to direct that NERC revise this standard to apply to all protection system components, at least until NERC completed its analysis of the Order No. 754 data responses. After review of that data, the NERC SPCS and SAMS recommended including protective relays, DC control circuitry, and station DC supply in the standard. This recommendation was based on the survey results regarding the prevalence of non-redundant protective equipment and the simulated disturbance magnitude of a failure of non-redundant equipment. The SPCS and SAMS report, did not, however, quantify the likelihood of each type of non-redundant protection component failure. Thus, it is hard to fully agree with the SPCS/SAMS recommendations at this time (and the Standard Authorization Request is only to "consider" them rather than "address" them).

WAPA does not believe that it is necessary to include analysis of all of these non-redundant Protection System component failures in the TPL standards at this time. Alternatively, if they are included, then they should be treated similarly to the current treatment of Extreme Events where there are no strict performance requirements or mandates to create Corrective Action Plans. In fact, the SPCS and SAMS report suggested that auxiliary relay and lockout relay failures were the main culprit in previous disturbances but failures of other equipment are generally rare or unimpactful (p.7). If anything, the P5 category expansion should be limited to auxiliary and lockout relays. This would allow utilities to focus their money and attention to mitigating the most severe potential impacts rather than building redundancy into systems where it will most likely never be needed.

WAPA recently studied the cost of eliminating single points of failure at a typical older substion. WAPA estimates that building full redundancy will likely cost over $1.3 million and take about a year and a half to implement. The main reason why it takes this long is due to scheduling outages. During outage timeframes, WAPA may have to curtail transmission or generation schedules, which many WAPA customers and staff would view as a decrement to reliable operations. The commissioning of new relays also requires significant testing, which conceivably puts WAPA at greater risk for human error. Furthermore, WAPA does not have any record of a P5 or EE2d type of event in the last 50+ years. Just building redundancy into substations will be a challenge to explain to WAPA ratepayers, and it may prove extremely difficult if WAPA is required to add costs and time for DC control circuitry equipment. Instead, WAPA may desire to focus its limited resources on developing replacement plans for aging equipment (e.g. transformers) or improving security measures.

As a reference, here is the language from SAMS Table 1.3. *DC Control Circuitry: The protection system includes two independent DC control circuits with no common DC control circuitry, auxiliary relays, or circuit breaker trip coils. For the purpose of this data request the DC control circuitry does not include the station DC supply or the main DC* *distributionpanel(s), but does include all the DC circuits used by the protection system to trip a breaker, including any DC control circuit (branch) fuses or breakers at the main DC distribution panel(s).*

In addition to the concerns mentioned above, WAPA suggestions the following clarification of components of a protection system (Footnote 13).

Suggested Language:
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 used for primary protection;
2. A single communications system, necessary for correct operation of protective functions, which is not monitored or not reported;
3. A single DC supply associated with protective functions that is not monitored for both low voltage and open circuit, with alarms centrally monitored;
4. A single DC Control Circuitry that causes the primary and local backup protection system to not operate properly and triggers remote delayed clearing.

4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

☐ Yes
☒ No

Comments:

The additions which require a Corrective Action Plan for the subset of Table 1 extreme events (footnote 13, 2e-2h) are beyond what is stated in the conclusion of the SPCS and SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report. This report recommended the following:

Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults the described component failures of a Protection System[13] that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Corrective Action Plans for low probability extreme events should not be required. However, it is reasonable that if Cascading is caused by the occurrence of an extreme event, an evaluation of possible actions designed to reduce the likelihood be conducted, as is currently stated in TPL-001-4 for extreme events (R4.5). Based on the conlusion of the above mentioned SPCS and SAMS report, it is understood that the intent should be to clarify that **both** three-phase faults with stuck breaker **and** failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing shall be considered as part of those extreme events in Table 1 that are expected to produce more severe System impacts in accordance with the existing language of TPL-001-4 R4.5. In other words, clarify that the "or" in Table 1 – Extreme Stability Events should not be interpreted as you only need to consider either stuck breaker or relay failure in R4.5. This is accomplished by simply breaking these events apart in Table 1 as shown below (and as in the current TPL-001-5 draft):

2. Local or wide area events affecting the Transmission System such as:
    a. 3Ø fault on generator with stuck breaker[10] resulting in Delayed Fault Clearing.
    b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
    c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
    d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
    e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
    h. 3Ø fault on bus section with failure of a non-redundant comoponent of a Protection System[13] 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

To further emphasize this point, refer to the alternatives for addressing reliability risks associated with single points of failure outlined in Charper 2 of the SPCS and SAMS report:

- *Place additional emphasis on assessment of a three-phase fault and protection system failure*
    - *Provideds assurance that areas where a three-phase fault accompanied by a single point of failure that will cause an adverse impact are identified and evaluated*
- *Elevate to a planning event with its own system performance criteria*

- *Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event*
- *Keep as an extreme event with no change (other than footnote 13)*
  - *Does not provide assurance a three-phase fault with protection system failure is studied in planning assessments*

From the above language describing the considered alternatives, it can be ascertained that the concern is ensuring that the language in the standard be updated to assure three-phase faults with protection system failure are studied in planning assessments, not that a "subset of Table 1 Extreme Events" be created that are treated differently than other Extreme Events by elevating them to requiring Corrective Action Plans because "the probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event". Furthermore, there is no technical justification to elevate a three-phase fault with failure of a non-redundant component of a Protection System events above three-phase fault with stuck breaker events.

Although WAPA strongly disagrees with requiring a Corrective Action Plan for this "subset of Table 1 extreme events", if this requirement is carried forward WAPA recommends creating a separate P8 Event for these three-phase failure of a non-redundant component of a Protection System events because it makes Table 1 clearer to read, understand and differentiate between what is required of these events compared to other Extreme Events.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (all events): 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 (P0 through P7 events 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 (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	3Ø	EHV, HV	Yes	Yes

5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

☒ Yes
☐ No

Comments:

6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

☒ Yes
☐ No

Comments:

7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

☐ Yes
☒ No

Comments:

There is a concern that utilities will not be able to meet the 60 month implementation plan in a reliabile manner. Unlike other potential areas identified in Planning Studies where the system may not meet the System Performance Requirements outlined in Table 1, other temporary reliable solutions, such as the use of Operating Procedures, are available that can be implemented until a long term solution (capital project) is completed. In many instances the only way to fully mitigate impacts resulting from "failure of a non-redundant component of a Protection System" event is to add redundancy. If this cannot be achieved in 60 months utilities may be forced to make undesirable system protection adjustments that could result in a higher rate of misoperations, reduction of system security, and reduced reliability until redundancy can be added. This should not be interpreted as utilities ignoring the importance of adding redundancy at critical points on the system, but implementation should be done on a cost/benefit (risk assessment) basis that takes into consideration the resources individual utilities have to adequately address areas of concerns resulting form single points of failure. In other words, the timing requirement of the implementation plan should not be so prescriptive that it leads to greater reliability risks than the conerns associated with the potential consequences of a single point of failure event.

8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☒ No

Comments:

9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

☒ Yes
☐ No

Comments:

10. Do you have any other general recommendations/considerations for the drafting team?

☒ Yes
☐ No

Comments:

WAPA believes there is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system.

Frequency of these SPF events are so seldom, they do not warrant the cost to eliminate unless there are significant risks to the transmission system such as instability and cascading. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.

Table A: Criteria for Buses to be Tested
Buses operated at 200 kV or higher with 4 or more circuits
Buses operated at 100 kV to 200 kV with 6 or more circuits
Buses operated at 100 kV or higher that directly supply off-site power to a nuclear generating station
Any additional buses operated at 100 kV or higher that the Transmission Planner believes are necessary for the reliable operation of the bulk power system

Table C: Performance Measures
1. Loss of synchronism of generating units totaling greater than 2,000 MW or more in the Eastern Interconnection or Western Interconnection, or 1,000 MW or more in the ERCOT or Québec Interconnections
2. Loss of synchronism between two portions of the system
3. Negatively damped oscillations

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2015-10 Single Points of Failure | TPL-001-5

Comment Period Start Date: 4/25/2017

Comment Period End Date: 5/24/2017

There were 63 sets of responses, including comments from approximately 180 different people from approximately 129 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards Development, Steve Noess (via email) or at (404) 446-9691.

Questions

1. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?
2. Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?
3. Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?
4. Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?
5. Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))
6. Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?
7. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?
8. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?
9. Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?
10. Do you have any other general recommendations / considerations for the drafting team?

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Portland General Electric Co.	Angela Gaines	1,3,5,6	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
Independent Electricity System Operator	Ben Li	2	NPCC	ISO/RTO Council Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Greg Campoli	NYISO	2	NPCC
					Ali Miremadi	CAISO	2	WECC
					Ben Li	IESO	2	NPCC
					~~Kathleen Goodman~~	~~ISO-NE~~	~~2~~	~~NPCC~~
					Nathan Bigbee	ERCOT	2	Texas RE
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Steve McElhaney	CooperativeEnergy	4,6	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Matthew A. Caves	Western Farmers Electric Cooperative	1,5	SPP RE
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Associated Electric	Mark Riley	1,3,5,6			Mark Riley	Associated Electric Cooperative, Inc.	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Cooperative, Inc.				AECI & Member G&Ts	Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Lower Colorado River Authority	Michael Shaw	1,5,6		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no ISO-NE, NYISO and NextEra	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chuck Lawrence	American Transmission Company	1	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Deborah McEndafffer	Midwest Energy, Inc	NA - Not Applicable	NA - Not Applicable
					Robert Gray	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					Rober Hirchak	Cleco	1,3,5,6	SPP RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					John Allen	City Utilities of Springfield, Missouri	4	SPP RE
					Jonathan Hayes	Southwest Power Pool, Inc	2	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kevin Giles	Westar Energy	1	SPP RE
					Liam Stringham	Sunflower Electric Power Corporation	1	SPP RE
					Louis Guidry	Cleco	1,3,5,6	SPP RE
					Michelle Corley	Cleco Corporation	3	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Steve McGie	Board of Public Utilities (BPU) Kansas City, Kansas	3	SPP RE
					J. Scott Williams	City Utilities of Springfield, Missouri	1,4	SPP RE
					Joe Fultz	Grand River Dam Authority	1	SPP RE
					Thomas Maldonado	Excel Energy	NA - Not Applicable	SPP RE
Santee Cooper	Shawn Abrams	1,3,5,6		Santee Cooper	Tom Abrams	Santee Cooper	1	SERC
					Rene' Free	Santee Cooper	1	SERC
					Weijian Cong	Santee Cooper	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chris Wagner	Santee Cooper	1	SERC
					Anthony Noisette	Santee Cooper	1	SERC
PPL – Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

SDT Response to Informal Industry Comments

The SDT appreciates the depth of the industry comments and has sought to address each comment submitted during the review of the proposed TPL-001-5 draft Reliability Standard. The SDT has dissected the industry input for each informal comment period question into common themes and seeks to address each here.

Q1	Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that move away from the 6 month duration outage to limited known outages selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) for the time horizon of the operations planning horizon through the near term planning horizon?

In response to Q1, the industry comments ranged from:

- Concerns with "consultation with Reliability Coordinator" text.
- If the RC is required to participate in TPL-001-5, then the RC should be identified as an applicable entity in the TPL standard.
- Outage coordination is an operational issue, not a planning issue.
- IRO-0017 sufficiently covers outage coordination.
- May create additional or duplicate work.
- Consider reducing the 6-month minimum duration for outages that should be considered.
- Need to strengthen the existing Table 1 - P3 and P6 Planning Events to ensure that all outages are accommodated.

Upon reviewing the industry comments, the SDT noted the following considerations of FERC Order 786:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;

- Planned outages are not “hypothetical outages” and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year one or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

The SDT considered the wide range of industry comments received as well as the NERC System Analysis and Modeling Subcommittee (SAMS) report to the NERC Planning Committee (that was also vetted through the industry) and believes the most cost-effective means to address the intent of the NERC directives in FERC Order 786 is to use IRO -017-1 as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate potential reliability impacts. The NERC SAMS recommended that IRO-017-1 should be used to assure that all types of known scheduled outages are being reviewed and coordinated, as well as used to direct actions that must be taken, to mitigate reliability impact (“FERC Order 786 Directives” - NERC SAMS White Paper, July 2016, pg. 3). As directed by FERC Order 786 (Para 40) and consistent with the NERC SAMS recommendation, the TPL-001-5 Requirement R1.1.2 is modified by removing the six month duration criterion. SAMS also recommended that language be added to R1.1.2 referencing the outage coordination process developed in IRO-017-1 Requirement R1. The drafting team believes that requiring consultation with the Reliability Coordinator when the Planning Coordinator and Transmission Planner maintain System models that represent known outages is consistent with IRO-017-1 Requirement R1, as well as Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon. In this way, IRO-017-1 R1 requires the Reliability Coordinator to identify outages and TPL-001-5 R1.1.2 requires the Planning Coordinator and Transmission Planner to consult with the Reliability Coordinator on which known outages to represent in System models for the Near-Term Planning Horizon (the transmission planning period that covers Year One through five).

The term consultation was used in Requirement R1.1.2 to specify that the Reliability Coordinator does not direct which known outages shall be represented in the System models maintained by the Planning Coordinator and Transmission Planner. Instead, the Planning Coordinator and Transmission Planner consult with the Reliability Coordinator to obtain additional information beyond simply what outages are scheduled in outage coordination systems (e.g. CROW, NERC SDX, etc.). The additional information that the Reliability Coordinator can provide to aid the Planning Coordinator and Transmission Planner when selecting known outages to represent may include: the likelihood of the known outage occurring (e.g., outages are not hypothetical, consistent with FERC Order 786, Paragraph 42), the potential for known outages to be concurrent (e.g., situations when Table 1 Category P3 and P6 events are not sufficient to represent System conditions, consistent with FERC Order 786, Paragraph 44), or expected known outage duration (e.g. situations when outages may extend from the Operations Horizon into the Near-Term Planning Horizon; situations when outages span multiple seasons or peak and off-peak periods, consistent with FERC Order 786, Paragraph 41). It is noted that the term consultation has been used elsewhere in the Reliability Standards (e.g. PRC-023-4, VAR-001-4.1) to indicate that other entities may have valuable information necessary for consideration, but where it may be inappropriate for those entities to direct decision-making.

To address outage coordination the SDT is initiating a SAR to enhance IRO-017 to include known outages in the Near-Term Planning Horizon. The specific language will be developed subsequent to an IRO-017 SAR and SDT. The SAR will include the objective to use the coordination process developed pursuant to IRO-017-1 Requirement R1 to direct how all known scheduled outages are reviewed and the actions that must be taken. The following objectives should be added to IRO-017-1 Requirement R1:

- Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into the Near Term Assessment of the Planning Horizon required by TPL-001-4, and whether and which of these known scheduled outages will be studied in this Assessment.
- Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.

The TPL SDT believes that modifying R1 in such as way offers win-win collaboration between the Reliability Coordinator and the planning entities. The communication process developed in accordance with IRO-017 to meet the above objectives will provide the opportunity for an RC to forward outages that have been scheduled in the near term planning horizon to the Planning Coordinator for analysis as well as providing the opportunity for the Reliability Coordinator to make the Planning Coordinator aware of other operational issues that may be developing. The Planning Coordinator will gain additional situational awareness from the Reliability Coordinator perspective as well as gaining insight on issues for possible inclusion in the Near-Term Planning Horizon.

Q2	Do you agree with the proposed changes to Requirement 2, Part 2.4.5 which addresses the Federal Energy Regulatory Commission (FERC) order to add the spare equipment with long lead time to the dynamics analysis?

The SDT considered the industry comments regarding Question 2 and maintained the proposed TPL-001-5 language that addresses FERC Order 786 Paragraph 89.

Q3	Do you agree with the further clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events?

The SDT paid considerable attention to the depth of the industry comments received regarding Question 3 and has sought to address general and specific industry comments with the following response. If one theme, more than any other, was communicated by industry it was to desire specificity about the Protection System components that must be redundant. The SDT seeks to make clear that the draft Footnote 13, as well as changes to the P5 and extreme events, do not prescribe any level of redundancy. Instead, the changes proposed by the SDT prescribe that SPF in a limited set of non-redundant Protection System components must be considered when assessing system performance given the P5 and extreme events. The performance requirements of TPL-001-5 remain unchanged; the changes to Footnote 13 are intended to improve assessments of existing or planned System equipment that may harbor risks to reliability.

Industry comment: The expansion of components that must be considered when evaluating redundancy will cause industry to perform many more studies, expand equipment monitoring programs, and install redundant equipment. These actions are unwarranted because of the low probability of failure of these non-redundant components.

SDT rationale: The industry has been aware of concerns about Protection System component single point-of-failure (SPF) and corresponding risks to the BES since as early as the March 30, 2009 NERC Alert. The draft TPL-001-5 language proposed by the SDT is consistent with how other identified risks to reliability are incorporated into the Transmission System Planning standard, including similar assessment of low probability events (e.g., breaker failure). The changes to Footnote 13 do not prescribe any level of redundancy. On the contrary, what the SDT has proposed in TPL-001-5 is to specify which non-redundant components of a Protection System must be considered when assessing whether a failure will lead to Delayed Clearing. The purpose of proper simulation of the Planning and Extreme events of TPL-001-5 Table 1 is to ensure the System meets performance requirements. The SDT intends for the accuracy of those simulations to be enhanced by “raising the bar” on SPF.

Industry comment: The Protection System components included in Footnote 13 are unclear, require additional clarity, and should be more prescriptive.

SDT rationale: The SDT agrees with the industry comments. Upon the first release of the proposed TPL-001-5, the SDT desired to maintain the components considered in Footnote 13 as general as possible, while still adhering to the NERC Glossary of Terms definition of Protection System. However, the SDT acknowledges that more specificity within Footnote 13 will better align with the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" and limit the scope of Protection System components considered for non-redundancy. The proposed revised language is incorporated into the revised proposed TPL-001-5.

Industry comment: The rationale section for the Table 1 P5 event and Footnote 13 should be revised.

SDT rationale: The SDT agrees with the comment and made changes to the rational section, as follows.

<u>Revised Paragraph 1:</u> The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that will result in Delayed Fault Clearing. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

<u>Revised Paragraph 5:</u> [Footnote 13, Part 1] The drafting team sought to limit the scope of protective relays considered non-redundant components of a Protection System in the following ways:

1. May experience a single point of failure.
2. Respond to electrical quantities. Relays that do not respond to electrical quantities, e.g. sudden pressure, are always used in conjunction with relays that respond to electrical quantities and may offer some redundancy.
3. Are necessary for high-speed or Normal Clearing. Given that typical Protection System designs implement primary protection at the local terminal for Normal Clearing and backup protective relaying locally and remotely for Delayed Clearing, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

<u>Revised Paragraph 6:</u> [Footnote 13, Part 3] Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. Although the SAMS/SPCS report noted that a SPF in a communication system posed a lower level of risk, the drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that

Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all leading to Delayed Clearing, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard.

Industry comment: Are Protection System components that protect non-BES equipment connected to the BES buses included in Footnote 13?

SDT rationale: The TPL-001-5 standard establishes Transmission system planning performance requirements whereby each Transmission Planner and Planning Coordinator prepares an annual Planning Assessment of its portion of the BES. The TPL-001-5 Table 1 prescribes the System performance requirements applicable to Facilities given planning and extreme events. By proposing changes to Footnote 13, the SDT prescribes which non-redundant components of a Protection System must be considered for SPF. The failure of a non-redundant component of a Protection System may lead to Delayed Clearing given a fault located on the BES or on non-BES equipment, and should be appropriately simulated.

Industry comment: Single Protection System components of Footnote 13 should be clarified to mean only those single Protection System components that isolate the fault being studied.

SDT rationale: The SDT disagrees with the need to clarify that non-redundant Protection System components must be associated with clearing the fault. The SDT intention is to ensure failure of a non-redundant Protection System component that leads to Delayed Clearing be properly assessed. A non-redundant Protection System component that does not participate in the Normal Clearing of a fault, cannot cause Delayed Clearing if it fails.

Industry comment: Are Protection System components that protect non-BES equipment connected to the BES buses included in Footnote 13?

SDT rationale: The TPL-001-5 standard establishes Transmission system planning performance requirements whereby each Transmission Planner and Planning Coordinator prepares an annual Planning Assessment of its portion of the BES. The TPL-001-5 Table 1 prescribes the

System performance requirements applicable to Facilities given planning and extreme events. By proposing changes to Footnote 13, the SDT prescribes which non-redundant components of a Protection System must be considered for SPF. The failure of a non-redundant component of a Protection System may lead to Delayed Clearing given a fault located on the BES or on non-BES equipment, and should be appropriately simulated.

Industry comment: Single Protection System components of Footnote 13 should be clarified to mean only those single Protection System components that isolate the fault being studied.

SDT rationale: The SDT disagrees with the need to clarify that non-redundant Protection System components must be associated with clearing the fault. The SDT intention is to ensure failure of a non-redundant Protection System component that leads to Delayed Clearing be properly assessed. A non-redundant Protection System component that does not participate in the Normal Clearing of a fault, cannot cause Delayed Clearing if it fails.

Industry comment: The parenthetical portion of the TPL-001-4 Footnote 13 that specifies which relay types are considered should not be removed in the proposed TPL-001-5 Footnote 13.

SDT rationale: [Footnote 13, Part 1] The SDT disagrees with the comment, primarily because all relay types responding to electrical quantities used for primary protection (Normal Clearing) are included in the TPL-001-4 Footnote 13. In other words, the SDT believes that removing the specific relay types allows the applicable entity to consider whether single protective relays may be non-redundant and, if failed, would lead to Delayed Clearing.

Industry comment: A communication system was not part of the Standards Authorization Request as one of the non-redundant components of a Protection System to consider for inclusion in Footnote 13.

SDT rationale: [Footnote 13, Part 2] Consistent with the direction in the SAR, the SDT considered the recommendations for modifying TPL-001-4 as identified in the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request". As part of that consideration, the SDT thoroughly reviewed the methodology as well as the findings of the report, such as "a single point of failure in a communication system poses a lower level of risk". However, the SAMS/SPCS report "only analyzed communication equipment in protection systems where communication-aided protection is needed to satisfy the system performance required in NERC Reliability Standards." The SDT believed that this report assumption necessitated that communications be included in the potential non-redundant components of a Protection System considered in Footnote 13 for two reasons. First, the system performance required, referred to as Performance Measure in the Order 754 data request, was loss of synchronism and/or negatively damped oscillations. This performance requirement is significantly different than the performance requirements of Planning Events of TPL-001-4 Table 1. Second, the SAMS/SPCS report acknowledged that: “the risk associated with a given protection system is dependent on the protection system design. Depending on the protection system design, a single point of failure may result in a failure of the communication-aided system to initiate a high-speed trip (e.g., a permissive overreaching transfer trip scheme), in which case delayed tripping will occur.” The SDT believed that evaluating redundancy of Protection System components is integral to properly assessing system performance for the P5 and applicable extreme events; therefore, without presuming Protection System design, the non-redundant communication system must be included in Footnote 13. Additionally, the SAMS/SPCS report stated that communication systems “are typically monitored and alarmed via SCADA or tested periodically”, further mitigating the risk of single point-of-failure. The SDT adapted this SAMS/SPCS finding to limit the communication systems to be considered as part of Footnote 13 to those which are not monitored or not reported.

Industry comment: The reference to single DC supply associated with protective functions in Footnote 13 is not specific enough, e.g. battery health.

SDT rationale: [Footnote 13, Part 3] The SDT intended single DC supply to refer to the entire set of equipment that comprises the DC source supplying power to Protection System components necessary for Normal Clearing. In other words, the SDT sought to specify that, within the entire set of equipment comprising the single DC supply, a failure of a piece of equipment that causes the single DC supply to be unable to source power to the protective functions necessary for Normal Clearing must be considered as part of Footnote 13. Relatedly, the SDT agrees that a typical station battery bank is only one part of the single DC supply. Further, a failure of a station battery may be masked for short time by the AC-sourced station battery charger. However, the SDT did not prescribe specific DC supply design configurations. Instead, the SDT emphasized that the single DC supply must be considered for susceptibility to SPF as part of Footnote 13.

Industry comment: It is unclear whether Footnote 13, Item 4 intends for trip coils to be redundant.

SDT rationale: [Footnote 13, Part 4] The SDT intends for trip coils to be considered as part of non-redundant components of a Protection System that may be SPF. It is clear that, given a failure of a single trip coil without a second (e.g., parallel) trip coil, a fault necessitating the opening of the breaker commanded by the unary trip coil will not occur, leading to Delayed Clearing. The SDT does not intend to prescribe whether redundant trip coils are required; instead the SDT has proposed language that requires that non-redundant DC control circuit components, such as trip coils, be considered as part of Footnote 13. The SDT does note that, in most instances, a fault and a failure of a non-redundant trip coil may lead to breaker failure initiation, resulting in Delayed Clearing.

Industry comment: [Footnote 13, Part 4] DC control circuitry should be allowed similar monitoring provisions as with the other parts of Footnote 13.

SDT rationale: The SDT disagrees with the industry comment. While trip coil monitoring devices are commonly available to give awareness of potential trip coil failure, the SDT believes monitoring trip coil failure or relay trouble indication is insufficient to ensure that a SPF is not present within a single control circuit. Similarly, DC undervoltage relaying or other control circuit continuity monitoring may indicate a problem with part of the DC control circuit, but may not give awareness of SPF risks such as serial tripping devices (ANSI #86 and #94 devices). Therefore, The SDT did not incorporate a monitoring provision into Footnote 13, Part 4 and intends for non-redundant components within the DC control circuitry of a Protection System to be considered as part of Footnote 13.

Q4	Do you agree with the proposed Requirement 4, Part 4.6 additions which require a Corrective Action Plan for this subset of Table 1 extreme events (footnote 13, 2e-2h)?

The SDT recognized that the industry comments received regarding Question 4 were particularly negative. The SDT would like to address the most common comment received: requiring Corrective Action Plans as part of Requirement R4.6 goes beyond the scope of the SAR, was not part of the recommendations from the SPCS/SAMS report titled "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request", and/or is not justifiable given the low likelihood of occurrence. With regards to industry commenters, approximately two-thirds of respondents expressed this concern. The SDT acknowledges this comment and appreciates the majority of industry feedback. While it is clear that a SPF for a Protection System component may lead to significantly longer Delayed Clearing and notably worse system response than typically analyzed breaker failure conditions, the industry has indicated that the probability of simultaneous SPF occurrence with a bolted three-phase fault is low. Therefore the SDT has restored the assessment of SPF for a Protection System component with a three-phase fault to language consistent with TPL-001-4 Requirement 4.5.

The SPF for a Protection System component is an important topic that, the SDT believes, may involve risks that are underappreciated. The SDT considered using Corrective Action Plan changes in proposed Requirement 4.6 or a new Table 1 Planning Events Category P8 to emphasize the importance of this issue, but given the industry comments and lack of a FERC directive did not “raise the bar” at this time. The SDT would like to document an important considerations it considered, that the fault conditions and system performance requirement, referred to as Performance Measure, of the Order 754 data request were very similar to those of Extreme Events of TPL-001-4 Table 1, namely three-phase fault application and conditions that can indicate Cascading. The primary conclusive finding of the SPCS/SAMS report was: “analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.” Further, the SPCS/SAMS report concluded that: “additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure.” Despite the SPCS/SAMS report stopping short of recommending that a Corrective Action Plan be developed when analysis concludes Cascading is caused by the occurrence of a three-phase fault and a failure of a non-redundant Protection System component extreme event, the SDT considered this recommendation consistent with the SAR. However, lacking FERC directive, the SDT determined that the existing TPL-001-4 Requirement R4.5 to evaluate possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the SPF event was sufficient given the risk to reliability. However, Planning Coordinators and Transmission Planners should be aware of some important analytical considerations:

1. Breaker failure Delayed Clearing times are typically 7-14 cycles. This may be significantly shorter than the Delayed Clearing times experienced given a failure of a non-redundant Protection System component.
2. Cascading is significantly less likely to occur given breaker failure clearing times. However, the Delayed Clearing times experienced for three-phase fault and a failure of a non-redundant Protection System component could induce Cascading.
3. Experience has shown a single line-to-ground fault that remains un-cleared for a prolonged period may migrate into multiple phases. Therefore, while a single line-to-ground fault, that would otherwise be cleared, may rapidly become a three-phase fault before Delayed Clearing resulting from a failure of a non-redundant Protection System component.
4. Once assessed, demonstrating Cascading given the identified risk of a three-phase fault and a failure of a non-redundant Protection System component, the impacts to System reliability warrant mitigating plans, encompassed by a Corrective Action Plan.

Q5	Do you agree with the drafting team's approach which doesn't add additional applicable entities to the applicability of the standard? (e.g. RC, Transmission Operator (TO), Generator Operator (GO), Distribution Provider (DP))

The most prevalent industry comment regarding applicability was tied to maintenance outages considered in the Planning Assessment for the Near-term Planning Horizon. The industry comments indicated that the Reliability Coordinator should be added as a TPL-001-5 applicable entity. The second-most common industry comment was to not change the TPL requirements as proposed, but instrad IRO-017-1 should be modified to keep maintenance outage coordination within one standard, leaving the TPL-001-5 as a planning standard. Other prominent industry comments included: the Generator Owner and Transmission Owner should be added as applicable entities due to changes to "components" of Protection Systems; and, the Transmission Operator should be added, along with the Reliability Coordinator, given the inclusion of maintenance outages.

Given the challenges of requirements that span multiple Reliability Standards and the corresponding applicability concerns, the SDT has initiated the process to revise the existing SAR as well as propose a new SAR to enhance IRO-017 as the vehicle to identify and communicate known outages for the Near-Term Planning Horizon.

Q6	Do you agree with the 36 month implementation period to address All Requirements except for Requirement R4, Part 4.6, and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4, as well as the definitions?

The SDT considered the industry comments regarding Question 6 and maintained the proposed TPL-001-5 implementation plan.

Q7	Do you agree with the 60 month implementation plan for Requirement 4, Part 4.6 and Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4?

The SDT considered the industry comments regarding Question 7 and maintained the proposed TPL-001-5 implementation plan.

Q8	Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

Given the preponderance of industry comments regarding conflicts between IRO-17-1 and the proposed TPL-001-5, the SDT has initiated the process to revise the SAR, as well as propose a new SAR. Similarly, the SDT has removed the proposed Corrective Action Plan in Requirement R4.6 and maintained the existing TPL-001-4 Requirement R4.5.

The SDT would like to address the specific industry comment: due to the changes incorporated in this proposed TPL standard, Reliability Standard CIP-014-2 – Physical Security can be impacted with the outcome. The SDT understands that CIP-014 Requirement R4 Part 4.1.1.3 applies to 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. Depending upon the IROL methodologies defined in FAC-014-2, the proposed TPL-001-5 can result in a different scenario for applicable Transmission Facilities for CIP-014-2. However, the SDT believes there is no conflict between CIP-014-2 and the proposed TIP-001-5.

Q9	Do you agree with the teams proposed changes to align the VRF/VSLs for Requirement 4, Part 4.6 with the VRF/VSLs for Requirement 2, Part 2.7?

The SDT believes that the majority of industry comments regarding Question 9 are resolved with the removal of the Corrective Action Plan in Requirement R4.6.

Q10	Do you have any other general recommendations/considerations for the drafting team?

Given the significant changes that the SDT have made to the proposed TPL-001-5 subsequent to the first informal industry comment period, the SDT believes that it has addressed the industry recommendations with regards to topics covered in the Project 2015-10 SAR submitted in response to Question 10.

The SDT would like to address the specific industry comment: when providing additional clarity/rationale on the subject of redundancy, the drafting team consider referring to a technical paper developed by the System Protection Control Task Force developed in 2008 titled: "Protection System Reliability: Redundancy of Protection System Elements". The SDT has considered the technical paper developed in 2008. It is noted that the SDT has proposed the draft footnote 13 and changes to P5 such that it does not prescribe redundancy. Instead, the changes proposed by the SDT prescribe that SPF in a limited set of non-redundant Protection System components must be considered when assessing system performance given the P5 and extreme events.

Additionally, the SDT would like to address the specific industry: the proposed implementation plan makes reference to, in certain circumstances, carrying over from TPL-001-4 the 84-month exception (our word) period related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service, which is unclear. The SDT has proposed the 36-month implementation period to provide sufficient time for PCs and TP to update their annual assessment to include the new System models and studies required by the TPL-001-5. The additional 24-month CAP drafting period is to identify appropriate CAP related to SPF. The 84-month exception period related to CAP including Non-Consequential Load Loss and curtailment of Firm Transmission Service in TPL-001-4 was kept in the TPL-001-5 implementation plan so that the 84-months will not get inadvertently truncated.

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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 -MOD-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, Part2.6. 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, Part2.6 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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td><td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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.

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

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

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.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~4~~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:** 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~~

- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

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~~MOD-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) ~~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.

1.1.3. 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-010 and MOD-012, MOD-032~~ 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 ~~studied~~assessed. The ~~studies~~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, Part2.6. 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.

~~2.4.3.~~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.

~~2.4.4.~~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, Part2.6 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. ~~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. ~~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~~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. ~~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. ~~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. ~~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 ~~1.1 Compliance Enforcement Authority~~

~~Regional Entity~~ 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.

~~1.2~~ **Compliance Monitoring Period and Reset Timeframe**

1.4. :

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

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

~~1.3~~ **Additional Compliance Information**

1.6. :

None~~-~~.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

~~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)~~

~~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
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.

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~ non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay~~ 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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   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.
      ii. Loss of the use of a large body of water as the cooling source for 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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~d.~~i. 3Ø internal breaker fault. ~~e.~~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.

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
30-day Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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 MOD-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, ~~as selected in consultation with the Reliability Coordinator,~~ with known outages modeled as ~~specified~~ 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 ~~studied~~ assessed. The

~~studies~~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, Part2.6. 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 ~~studied. The studies~~assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 ~~categories~~category events identified in Table 1 ~~with~~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, Part2.6 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~~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.

~~4.1.3.1.~~4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

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

~~4.2.1.~~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:

~~4.2.1.1.~~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.

~~4.2.1.2.~~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.

~~4.2.1.3.~~4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

~~4.2.2.~~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.

~~4.3.~~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.

~~4.3.1.~~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.

~~4.4.~~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.~~

~~4.5.~~ ~~If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:~~

~~4.5.1.~~ ~~List System deficiencies and the associated actions needed to prevent the System from Cascading.~~

~~4.5.2.~~ ~~Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.~~

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 ~~M7~~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 Investigations
- Self-Reports
- Complaints

1.6. Additional Compliance Information: None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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.	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.	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 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.
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.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	for two of the categories (P1 through P7) in Table 1. OR 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.~~	OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				or joint responsibilities for performing required studies.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

<table>
<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>
<tr><td rowspan="2">P3
Multiple Contingency</td><td rowspan="2">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]</td><td>3Ø</td><td rowspan="2">EHV, HV</td><td rowspan="2">No[9]</td><td rowspan="2">No[12]</td></tr>
<tr><td>5. Single pole of a DC line</td><td>SLG</td></tr>
<tr><td rowspan="3">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="3">Normal System</td><td rowspan="2">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</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>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, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

Category	Initial Condition	Event 1	Fault Type 2	BES Level 3	Interruption of Firm Transmission Service Allowed 4	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event 1	Fault Type 2	BES Level 3	Interruption of Firm Transmission Service Allowed 4	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure[11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">Steady State & Stability
For all extreme events evaluated:
1. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.
2. Simulate Normal Clearing unless otherwise specified.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

Table 1 – Steady State & Stability Performance Extreme Events	
ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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. 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~~: a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying; b. A single communications system, necessary for correct operation of ~~protective functions~~ a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported; c. 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; d. A single control circuitry associated with protective functions ~~through~~including the trip coil(s) of the circuit breakers or other interrupting devices.

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.

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 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.

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 Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any~~ 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 ~~protective functions~~ a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;
- 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;
- A single control circuitry associated with protective functions ~~through~~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 ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items 2, 3, and 4

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

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 ~~R4, Part 4.6 and 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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2015-10 Single Points of Failure TPL-001

Do not use this form for submitting comments. Use the electronic form to submit comments on **TPL-001-5 – Transmission System Planning Performance Requirements**. The electronic form must be submitted by **8 p.m. Eastern, Monday, October 23, 2017.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at 404-446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

   ☐ Yes
   ☐ No

   Comments:

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

   ☐ Yes
   ☐ No

   Comments:

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

   ☐ Yes
   ☐ No

   Comments:

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs).

   ☐ Yes
   ☐ No

   Comments:

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

   ☐ Yes
   ☐ No

   Comments:

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

☐ Yes
☐ No

Comments:

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

☐ Yes
☐ No

Comments:

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

☐ Yes
☐ No

Comments:

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

☐ Yes
☐ No

Comments:

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

☐ Yes
☐ No

Comments:

14. Do you have any other general recommendations/considerations for the drafting team?

☐ Yes
☐ No

Comments:

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 instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

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:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

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.

Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement 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. **1.1** System models shall represent: **1.1.1.** Existing Facilities **1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	TPL-001-5, Requirement 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~~MOD-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. **1.1** System models shall represent: **1.1.1.** Existing Facilities **1.1.2.** Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at~~	Requirement R1 body. Updated referenced standard number in body of requirement. Requirement R1 Part 1.1.2 Consistent with FERC Order 786 Para 40, the six-month threshold that could exclude planned maintenance outages is eliminated. Consultation with the Reliability Coordinator given that the Planning Coordinator and Transmission Planner maintain System models that represent known outages is consistent with IRO-017-1 Requirement R1, as well as IRO-017-1 Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	~~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 ~~R.~~ 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	outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
TPL-001-4, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	TPL-001-5, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R2 Part 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.	TPL-001-5, Requirement R2 Part 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.	No modifications made.
TPL-001-4, Requirement R2 Part 2.4.3. 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.	TPL-001-4, Requirement R2 Part2.4.4~~3~~. 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.	<u>TPL-001-5, Requirement R2, Part 2.4.4</u> TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	
	TPL-001-5, Requirement R2 Part 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.	TPL-001-5, Requirement R2, Part 2.4.3 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.3.
	TPL-001-5, Requirement R2 Part 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	TPL-001-5, Requirement R2, Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.	
TPL-001-4, Requirement R3	TPL-001-5, Requirement R3	No modifications made.
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.
TPL-001-4, Requirement R4 4.2. Studies shall be performed to assess the impact of the extreme events which are	TPL-001-5, Requirement R4, 4.2. Studies shall be performed to assess the impact of the extreme events which are	<u>TPL-001-5, Requirement R4, Part 4.2</u> Modified the standard to differentiate between extreme events 2e-2h in the stability column of Table 1 from all other

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
identified by the list created in Requirement R4, Part 4.5.	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. ~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~	extreme events with respect to additional documentation required when analysis concludes Cascading occurs. While the extreme events 2e-2h in the stability column of Table 1 remain as extreme events within TPL-001-5, the additional documentation specified in Requirement R4, Part 4.2.2.1 is indicated due to the reliability risk given a three phase fault and extended Delayed Clearing that may arise from the occurrence of these events. Likewise, when analysis concludes there is Cascading, Requirement R4, Part 4.2.2.2 specifies that these events be reviewed in subsequent annual Planning Assessments.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

NERC

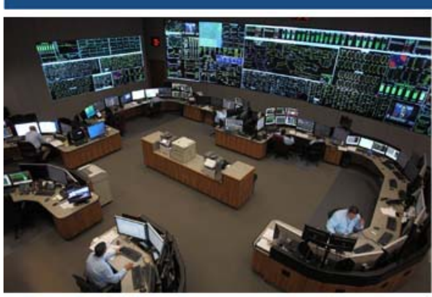
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

September 2017

RELIABILITY | ACCOUNTABILITY

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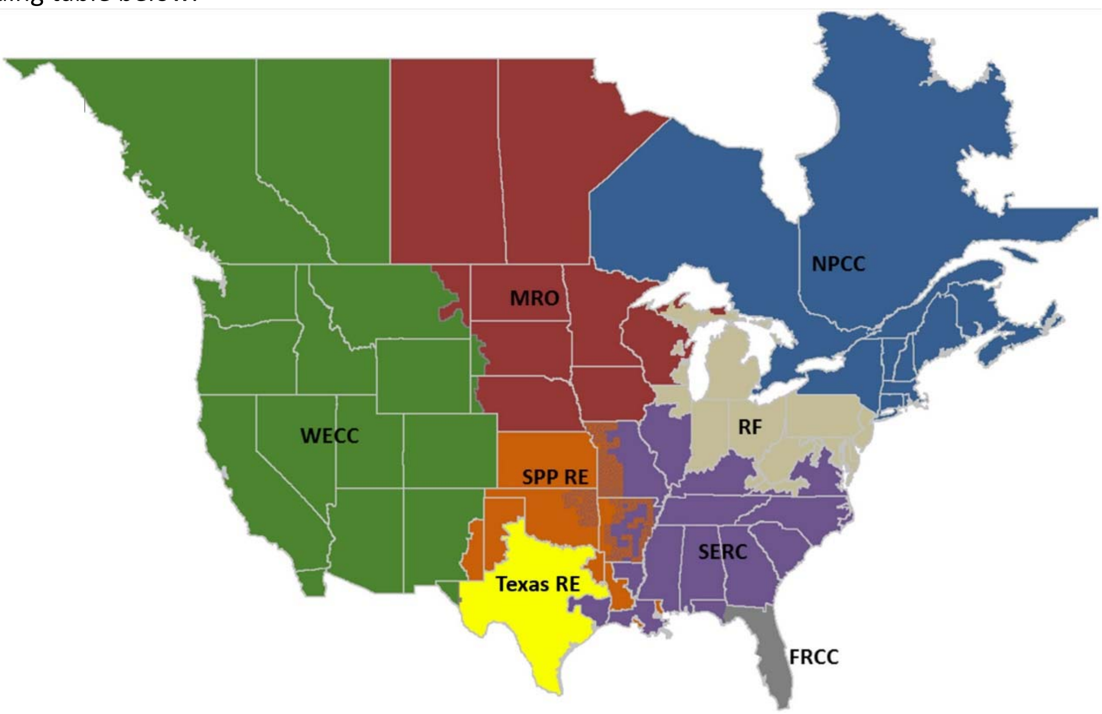
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and spare equipment strategy for stability analysis, and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standards Development Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*. Proposed revisions changes extreme event (3-phase fault) to include a fault and failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence of Protection System action leading to Delayed Clearing may be quite different between the two causalities. Footnote 13 expands Protection System components to be considered for Category P5 and for extreme events 2e through 2h.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, Category P3 and P6 do not sufficiently cover planned maintenance outages, and Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration and replace it with consultation with the Reliability Coordinator (RC) to identify known outages of significant facilities that cannot be readily managed through near-term operational coordination processes. Proposed revisions includes stability study for long lead equipment that does not have a spare.

Summary of proposed revisions:

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Modified how known outages are selected for study.
- Requirement R2, Part 2.1.3 – Modified the P1 contingency events simulated (steady state) for known outages.
- Requirement R2, Part 2.4.3 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R4, Part 4.2 – Added documentation requirement if Cascading observed given 3-phase fault SPF.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify SPF.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with single points of failure (SPF) in Protection Systems. The NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* provides extensive general discussion about the reliability risks associated with a SPF. Available

FERC Order No. 786

In Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order 786. The white paper provides extensive general discussion regarding the directives.

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[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the Technical Conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC PC/OC, summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated

[3] *See Industry Advisory: Single Point of Failure*

with SPF in Protection Systems that warrants further action. To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 standard drafting team are summarized in the following section.

Revisions to TPL-001-4

Table 1-Footnote 13

The SPCS/SAMS report recommended replacing “relay” with “component of a Protection System” in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of ’Protection System‘ for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

This revision to Footnote 13 clarifies the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Noting that Requirements R3.3.1 and R4.3.1 require simulation of Protection System action, the drafting team sought to limit the scope of Footnote 13, item 1 with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. An SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the drafting team did not include backup protective relays in the scope of Footnote 13, item 1 given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The drafting team recognizes that Bulk Electric System (BES) Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection. Subsequently, the P5 event for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay, but should be simulated for the sudden pressure relay clearing time, which may not be delayed. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event.

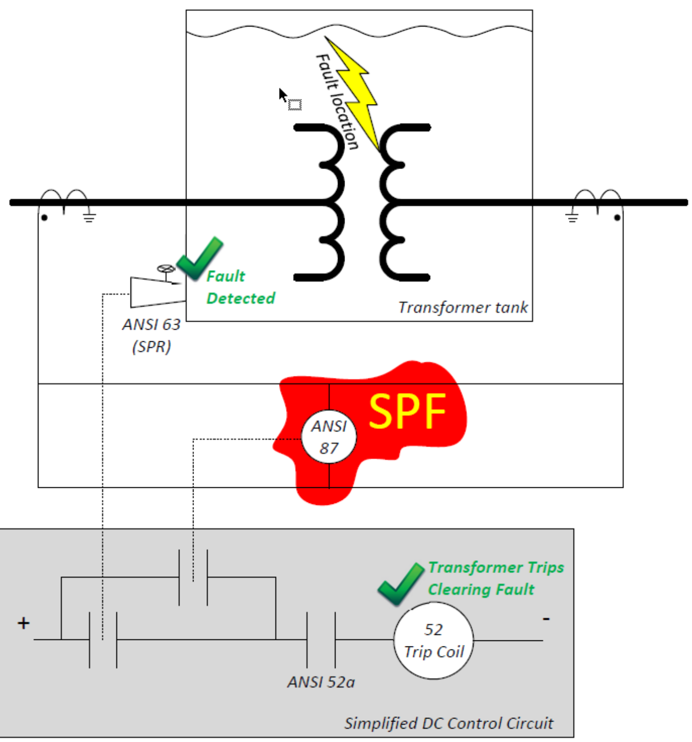

Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

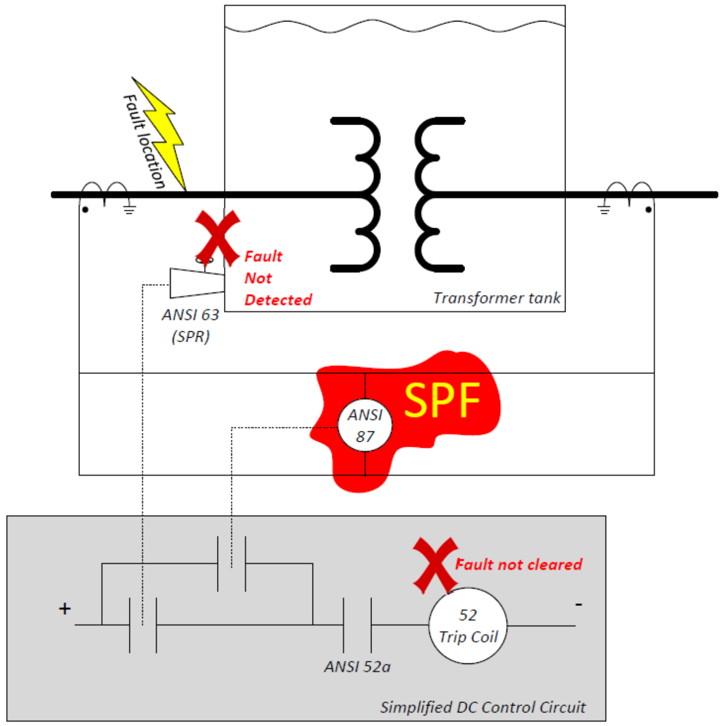

Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Requirement R4 Part 4.2 Extreme Events

Analysis of the data collected under the Order No. 754 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. This concern (the study of Protection System SPF) is appropriately addressed as an extreme event in TPL-001-4, Requirement R4, Part 4.2. While less probable than single-phase-to-ground faults, three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event. Therefore, TPL-001-4, Requirement R4, Part 4.5, which specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, is inadequate to address the risk of Protection System component SPF to the reliability of the BES. To address this concern the drafting team has modified Requirement 4 part 4.2.2 to require additional evaluation and documentation of possible actions designed to prevent the system from cascading for extreme events 2e-2h listed from the stability column of Table 1. The additional documentation shall list System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation. The analysis shall be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Thus, the drafting team has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but modified Requirement R4, Part 4.2.2 to require additional evaluation and documentation of possible actions, including a timetable of implementation, designed to prevent the system from Cascading. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- Additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

Footnote 13 provides the attributes of the specific non-redundant Protection System components that the entity shall consider for evaluation.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not “hypothetical outages” and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The coordination process developed pursuant to IRO-017-1, Requirement R1 should be used to direct how all known scheduled outages are reviewed and the actions that must be taken. The SAMS recommended that following objectives should be added to R1:

- Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into transmission plan development.
- Describe whether, how, and which known scheduled outages should be included in the Planning Assessment for the Near-Term Transmission Planning Horizon required by TPL-001-4.
- Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.

The NERC SAMS also recommended modifying TPL-001-4, Requirement 1.1.2 by removing “with duration of at least six months” and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

Revisions to TPL-001-4

Requirement R1 Part 1.1.2

The drafting team modified Requirement 1.1.2 consistent with FERC's directive and included necessary consultation with the Reliability Coordinator. This consultation is expected to assist the Transmission Planner and Planning Coordinator select known outages that are relevant, not hypothetical, and have a credible likelihood of being concurrent.

The change to Requirement 1, Part 1.1.2 eliminates the specified six month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term. This change is for coordination of known outages beyond the Operations Planning time horizon.

Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in

tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2 Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 standard drafting team revised TPL-001-4 Requirement R2 Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning and protection engineers that will need to conduct the studies and submit the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines.

Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant Protection System component could result in a potential reliability risk. These entities must provide this information, as well as resulting fault clearing times, to Transmission Planners for proper study.

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 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 R. 2.4.3.

Option 2

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~

Option 3

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least ~~six months~~ three months.

Option 4

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. These outage coordinations are required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The following is the option (Option 1) selected by the standard drafting team which satisfies the FERC Order. The following 1 option selected and in general aligns with the SAMS recommendation.

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 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 R. 2.4.3.

Spare Equipment Strategy FERC Order No. 786

FERC Order No. 786 Paragraph 89 the Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. See Paragraph 85 through 89 of Order No. 786 for a discussion on spare equipment strategy.

Overview of Commission Determination (Order No. 786 Paragraphs 88-89)

The commission stated in Order No. 786:

- Order No. 786 Paragraph 88: The commission agrees that NERC has met the spare equipment strategy directive for steady state analysis under TPL-001-4 R2, Part 2.1.5.
- Order No. 786 Paragraph 88: The Commission finds that a spare equipment strategy for stability analysis is not addressed under category P6.
- Order No. 786 Paragraph 89: The commission is not persuaded by the explanation of NERC and others that a similar spare equipment strategy for stability analysis would cause unjustified burden because stability analysis is already required under category P6.

Options Considered By Standard Drafting Team to Satisfy FERC Order No. 786

Since the FERC Order in Paragraph 89 was very specific, there was only one option considered by the standard drafting team that met the requirements of the FERC Order Paragraph 89 request.

Option 1 Addition of Part 2.4.5

Requirement R1, Part 1.1.2 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 ~~studied~~ assessed. ~~The studies~~ Based upon this assessment, an analysis shall be performed for the selected P1 and P2 ~~categories~~ category events identified in Table 1 for which the unavailability ~~with the conditions that the System~~ 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.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three phase faults the described component failures of a Protection System that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Options Considered By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language. These options are:

Option 1 Footnote 13

The Standard Drafting Team for TPL-001 considered revising footnote 13 to include all five components. In the NERC glossary of terms, a Protection System include five components. These are:

Protection System –

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

  a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

  b. 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;

  c. 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;

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

Option 3 Footnote 13

a. The components from the definition of Protection System" for the purposes of this standard include:
b. protective relays that respond to electrical quantities,
c. single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and
d. control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team selected Option 2 which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[2]:

For the purposes of P5 of this standard, components of a Protection System include the following:

a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

b. 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;

c. 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;

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

Addition of Corrective Action Plan for Extreme Event Three – Phase Faults:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754 data collection and report indicated a risk to the BES for three phase faults involving single points of failure of a protection system.

Options Considered By Standard Drafting Team to Satisfy FERC Order

Option 1:

Do not add anything for extreme event three-phase faults with protection failure.

Option 2:

Addition of Requirement 4 Part 4.2.1 and 4.2.2 as follows:

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.

[2] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

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

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

Standard Drafting Team Proposal

The standard drafting team selected Option 2 which was to add a requirement to require a Corrective Action Plan if a three-phase fault followed by a protection failure causes cascading.

Option 2:

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

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

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Standards Announcement

Reminder

Project 2015-10 Single Points of Failure

Initial Ballot and Non-binding Poll Open through October 23, 2017

Now Available

An initial ballot for **TPL-001-5 – Transmission System Planning Performance Requirements** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, October 23, 2017**

Balloting
Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience any difficulties in navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps
The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

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Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Open through October 23, 2017
Ballot Pools Forming through October 6, 2017

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Monday, October 23, 2017.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, October 6, 2017.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 13-23, 2017**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Latrice Harkness or at (404) 446-9728.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/107)
Ballot Name: 2015-10 Single Points of Failure TPL-001-5 IN 1 ST
Voting Start Date: 10/13/2017 12:01:00 AM
Voting End Date: 10/23/2017 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 244
Total Ballot Pool: 294
Quorum: 82.99
Weighted Segment Value: 30.5

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	15	0.234	49	0.766	0	4	11
Segment: 2	8	0.5	1	0.1	4	0.4	0	0	3
Segment: 3	67	1	13	0.236	42	0.764	0	2	10
Segment: 4	16	1	4	0.333	8	0.667	0	0	4
Segment: 5	65	1	15	0.3	35	0.7	0	3	12
Segment: 6	49	1	10	0.256	29	0.744	0	2	8
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	0	0	1	0.1	0	0	1
Segment: 9	1	0	0	0	0	0	0	1	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.5	4	0.4	1	0.1	0	1	0
Totals:	294	6.1	62	1.86	169	4.24	0	13	50

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Black Hills Corporation	Wes Wingen		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Third-Party Comments
1	Central Hudson Gas & Electric Corp.	Frank Pace		Abstain	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Negative	Comments Submitted
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Affirmative	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Negative	Comments Submitted
1	LS Power Transmission, LLC	John Seelke		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Negative	Third-Party Comments
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Negative	Comments Submitted
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Third-Party Comments
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Third-Party Comments
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted
2	California ISO	Richard Vine		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Aaron Austin		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	W. Dwayne Preston		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Negative	Third-Party Comments
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Negative	Comments Submitted
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	John Bee		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Negative	Third-Party Comments
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Third-Party Comments
3	Modesto Irrigation District	Jack Savage	Nick Braden	Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Third-Party Comments
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Third-Party Comments
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Negative	Third-Party Comments
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Third-Party Comments
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Negative	Third-Party Comments
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Negative	Comments Submitted
5	Entergy	Jamie Prater		None	N/A
5	Exelon	Ruth Miller		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Third-Party Comments
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Randy Crissman		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Dan Wilson		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Third-Party Comments
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Andrew Gallo		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton	Luiggi Beretta	Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Janis Weddle		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Third-Party Comments
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Brenda Hampton		None	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Negative	Third-Party Comments
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

BALLOT RESULTS

Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Non-binding Poll IN 1 NB
Voting Start Date: 10/13/2017 12:01:00 AM
Voting End Date: 10/23/2017 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 218
Total Ballot Pool: 274
Quorum: 79.56
Weighted Segment Value: 31.03

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	13	0.283	33	0.717	14	11
Segment: 2	7	0.2	0	0	2	0.2	1	4
Segment: 3	63	1	11	0.262	31	0.738	10	11
Segment: 4	15	1	3	0.3	7	0.7	1	4
Segment: 5	61	1	12	0.316	26	0.684	10	13
Segment: 6	47	1	8	0.286	20	0.714	8	11
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	6	0.6	5	0.5	1	0.1	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Totals:	274	6	54	2.146	120	3.854	44	56

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	John Brockhan		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Daniel Grinkevich		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	Georgia Transmission Corporation	Jason Snodgrass		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	LS Power Transmission, LLC	John Seelke		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Abstain	N/A
1	Portland General Electric Co.	Scott Smith		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla	Bret Galbraith	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Martine Blair		Affirmative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	California ISO	Richard Vine		None	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		None	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Aaron Austin		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	W. Dwayne Preston		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	None	N/A
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		None	N/A
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Negative	Comments Submitted
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		None	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Comments Submitted
3	Salt River Project	Rudy Navarro		Negative	Comments Submitted
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Clay Young		Affirmative	N/A
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Mark Oens		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		None	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart		None	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Negative	Comments Submitted
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Abstain	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		None	N/A
5	APS - Arizona Public Service Co.	Linda Henrickson		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Negative	Comments Submitted
5	Austin Energy	Jeanie Doty		Abstain	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Francis Halpin		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Thomas Rafferty		Negative	Comments Submitted
5	Entergy	Jamie Prater		None	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Randy Crissman		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Sarah Gasienica		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	N/A
5	Seattle City Light	Mike Haynes		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jerome Gobby		Affirmative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Westar Energy	Laura Cox		Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		None	N/A
6	APS - Arizona Public Service Co.	Bobbi Welch		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		None	N/A
6	Austin Energy	Andrew Gallo		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		None	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Abstain	N/A
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Jerry Nottnagel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton	Luiggi Beretta	Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		Affirmative	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	WEC Energy Group, Inc.	Scott Hoggatt		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Brenda Hampton		None	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Showing 1 to 274 of 274 entries

Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Open through October 23, 2017
Ballot Pools Forming through October 6, 2017

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Monday, October 23, 2017.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience any difficulties navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, October 6, 2017.** Registered Ballot Body members can join the ballot pools here.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An initial ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 13-23, 2017**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Latrice Harkness or at (404) 446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5
Comment Period Start Date:	9/8/2017
Comment Period End Date:	10/23/2017
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 IN 1 ST

There were 70 sets of responses, including comments from approximately 192 different people from approximately 118 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs).

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

14. Do you have any other general recommendations/considerations for the drafting team?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Mike Morrow	Midcontinent ISO	2	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Greg Campoli	NYISO	2	NPCC
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Matthew Goldberg	ISO NE	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC

					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Haley Sousa	5		Chelan PUD	Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
JEA	Joe McClung	1,3,5	FRCC	JEA Voters	Ted Hobson	JEA	1	FRCC
					Garry Baker	JEA	3	FRCC
					John Babik	JEA	5	FRCC
Associated Electric Cooperative, Inc.	Mark Riley	1		AECI & Member G&Ts	Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC
					Todd Bennett	Associated Electric Cooperative, Inc.	3	SERC
					Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC

					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
Lower Colorado River Authority	Michael Shaw	1,5		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					R. Scott Moore	Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC

					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC
					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC

					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Ed	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed	5	NPCC
Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Jim Nail	City of Independence, Power and Light Department	5	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Mike Kidwell	Empire District	1,3,5	SPP RE

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
SCL does not agree with the implementation of corrective action plan and the requirement for an annual review of the implementation status when analysis concludes there is Cascading caused by extreme events. Implementing actions for extreme events can be costly, and may not produce much benefit because of the low frequency of these types of events happening.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Requirement 4.2.2 NERC requires listing of possible actions, which is ok. However, 4.2.2.1 requires a timetable for implementation. In the past, the decision to mitigate extreme events has been left to the discretion of the Planning Coordinator. The PC is best able to set their risk tolerance or do a cost/benefit analysis to determine whether the Corrective Action Plan should be implemented. If the PC has no plans to implement the corrective action plan then why does a timetable need to determined and followed up in subsequent assessments.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

For extreme contingencies, SRP believes awareness of the impacts and the associated actions required to prevent the System from Cascading are sufficient. SRP recommends removing the the following language from 4.2.2.1. “and the associated timetable for implementation”	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy does not see any value added in extending the requirement to include event categories 2e-2h.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI contends that extreme events are simulated for informational purposes and development of actions needed to prevent the system from cascading should not be mandated, but should rather be left to the PC’s and TP’s judgement.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA does not agree with separating out extreme events in 2e-2h for mitigation, everything should be included in 4.2.1. BPA suggests removing any reference to implementation status and timetables. BPA suggests only including requirements for performing studies to assess the impact, analyzing the results and evaluating possible actions to reduce the likelihood or mitigate the consequences of extreme events.

BPA believes that it is not economically justifiable to require corrective action plans for low probability extreme events like these. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered if studies indicate there is the potential for cascading on critical parts of the system.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP disagrees. These proposed subrequirements exceed the authorization of the SAR. They attempt to convert certain extreme category events involving failure of a non-redundant component of a protection system into quasi-planning events where cascading is to be prevented (though while other performance requirements on consequential load loss, exceeding facility ratings, voltage deviations, etc., are omitted). In addition, AEP questions the benefit of devising preventive actions and an associated timetable, and performing an annual review of implementation status for mitigating actions that are supposedly never to be “required.”

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

In the past, the decision to mitigate extreme events has been left to the discretion of the Planning Coordinator. The TP is best able to set their risk tolerance or do a cost/benefit analysis to determine whether the Corrective Action Plan should be implemented. If the TP has no plans to implement the corrective action plan then why does a timetable need to be determined and followed up on in subsequent assessments.

Likes 0	
Dislikes 0	

Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS does not support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. It is AZPS's understanding that, based on previous stakeholder input, the SDT determined that a Corrective Action Program (CAP) requirement was not appropriate for these extreme contingencies. AZPS respectfully submits that, although the verbiage has been revised, the obligation on entities as a result of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 essentially amounts to a CAP requirement. In fact, AZPS reads the requirements of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 as providing an even more rigorous obligation than other CAP requirements. For example, in Requirement R2.8, the CAP requires 3 actions: (1) a list of deficiencies, (2) the actions necessary to address these, and (3) an annual review for continued validity and status. Parts 4.2.2, 4.2.2.1, and 4.2.2.2 require: (1) a list of deficiencies, (2) the actions necessary to address these, (3) a timetable for implementation, and (4) annual review for continued validity and status. Thus, in comparing requirements for a CAP and the requirements set forth in Parts 4.2.2, 4.2.2.1, and 4.2.2.2, it is clear that, despite stakeholder input, Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are still requiring a CAP even though the contingencies to be addressed are extreme, unlikely to occur, difficult and expensive to address, and unlikely to significantly improve reliability. Finally, AZPS respectfully suggests that it is not cost effective to attempt to resolve system efficiencies as a result of such extreme events. Such activities have a very low cost/benefit ratio, and will result in the unnecessary expenditure of resources by registered entities. For these reasons, AZPS cannot support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 and, therefore, cannot support an associated timetable for implementation or annual review of implementations status. AZPS recommends the deletion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 from TPL-001-5.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, AZPS submits the following suggested language:

4.2.2 If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e -2h the stability c and/or PC shall:

4.2.2.1 Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.
4.2.2.2 Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	

JEA appreciates the effort of the SDT addressing the directives from the Commission on Order No. 786 as well as the recommendation from the SPCS and the SAMS from the assessment of protection system single points of failure in response to Order No. 754. The clarification of relay to components of a Protection System with the additional footnote to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the report from Section 1600 Data Request following Order No. 754. This Order was issued directing NERC and Commission staff to initiate a process to identify any reliability issues for system performance following the loss of a single BES Element which appeared in the legacy TPL (version 0) standards. The conclusion from the report has rightfully and adequately addressed the Commission's concern. In general, the proposed TPL-001-5 removes the ambiguity from the legacy TPL standards for protection system failures.

However, the proposed new Requirement 4, Part 4.2.2, subparts 4.2.2.1 and 4.2.2.2 go beyond the recommendation from the Section 1600 Data Request report for Order No. 754. The issue of 'Cascading caused by the occurance of extreme events' is already addressed by part 4.2.1 that 'an evaluation of possible actions designated to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.' Besides, a Cascading caused by the extreme event due to protection system single points of failure (Table 1 Extreme Events – Stability 2e-2h) is no different than a Cascading due to any other extreme event (Table 1 Extreme Events – Stability 2a-2d, 2i-2j) - a Cascading is a Cascading; the end result is the same. And the Section 1600 Data Request report has very clearly put this in their conclusion in the second paragraph which is copied below verbatim:

"Additional emphasis in planning studies should be placed on assessment of three-phase faults involving protection system single points of failure. This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4, Part 4.5. From TPL-001-4, Part 4.5: 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."

The added clarification under Table 1 for Planning Event P5 and extreme event – stability 2e-2h along with footnote 13 sufficiently covers all the concerns that the Commission expressed in Order No. 754 as well as the conclusion and recommendation from the analysis for the same in the aforementioned report for the protection system single points of failure.

In addition, the conclusion of the above report did not recommend setting the bar "higher" for performance than it is for current TPL-001-4 for extreme events in TPL-001-4 Part 4.5 nor did the SAR authorize the SDT to do this. Any Cascading due to an extreme event is already addressed in the Commission approved TPL-001-4 in Requirement 4, Part 4.5 wherein an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is warranted.

Suggestion: Part 4.2.2, subparts 4.2.2.1 and 4.2.2.2 of the Requirement 4 is not needed as the issue of Cascading due to the extreme events is already covered by Part 4.2.1. Delete "excluding extreme events 2e-2h in the stability column" from Part 4.2.1 and it will cover ALL the Cascading due to extreme events

Likes 2	JEA, 5, Babik John; Seminole Electric Cooperative, Inc., 1,3,4,5,6, Ward Kristine
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy recommends that the Standard Drafting Team remove the timetable language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted."	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
NVE does not agree that an implementation plan with a timetable should be created for a subset of extreme events. Given the low probability of extreme events, NVE suggests only including the requirements for performing studies to analyze the results, assess the impacts and evaluate possible actions to reduce the likelihood or mitigate the consequences of extreme events. Additionally, the wording in R4.2.1 is nearly identical to the wording in the last sentence in R4.5. NVE suggest moving R4.2.1 – R4.2.2.2 and incorporating it into R4.5	
Likes 0	
Dislikes 0	
Response	

ALAN ADAMSON - New York State Reliability Council - 10	
Answer	No
Document Name	
Comment	
Part 4.2.2 of TPL-001-5 implies a requirement to implement actions to prevent the System from Cascading caused by extreme events, a criterion beyond the basic design and planning criteria. This requirement essentially moves such events into the “Steady State & Stability Performance Planning Events” table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listing the 2a to 2j events under the Extreme Event table. We objected to the previous draft TPL-001 revision because it called for a Corrective Action Plan (CAP) to avoid or mitigate such reliability impacts. Although this new draft standard removed a specific CAP requirement, it appears that this revised version continues to require implementation of actions to mitigate or avoid Cascading due to low probability	

extreme events, no matter the cost. We have no issue with requiring an evaluation of possible actions needed to prevent the System from Cascading, but we do object to a further requirement to implement an action or actions without considering cost and other factors.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA believes there is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system. We would also like to point out that there is no corresponding directive from FERC in the SAR.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase “excluding extreme events 2e – 2h in the stability column”. The strategy to manage extreme events should be the same for all categories of extreme events – and as such, the requirements in 4.2.1 (i.e., evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the events(s) shall be conducted) is sufficient.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No

Document Name	
Comment	
No. Question 1 and the referenced standard language state that a CAP is required but Question 2 implies that implementation of the CAP is not required. The SDT should consider clarifying how implementation status will be reviewed when no implementation is actually required. This lack of clarity may lead to inconsistent interpretation by Registered Entities as well as Regional Entities on what constitutes compliance.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments	
Likes 1	Seminole Electric Cooperative, Inc., 1,3,4,5,6, Ward Kristine
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	

Although the drafting team made its rationale clear for including a requirement for entities to document an associated timetable and perform annual reviews for the extreme events 2e-2h that result in cascading, SCE advocates that this language confuses the intent and will create compliance ambiguity in the future. SCE proposes that the drafting team remove sub-requirement R4.2.1 and R4.2.2 (and the underlying R4.2.2.1 & R4.2.2.2) entirely. This change will significantly reduce the confusion for the intention to not obligate entities to actually implement actions identified, and it will keep the compliance obligation clear in the future. Entities should look into actions that may reduce exposure or impact for 2e-2h in the same manner as other extreme events. Requiring a timetable without an obligation to implement does not add value to system planning.

Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) disagrees with the wording in Requirement R4, Parts 4.2.2.1 and 4.2.2.2 related to implementation. The wording related to implementation could be interpreted as requiring the actual implementation of actions identified as being needed to prevent the System from Cascading. Additionally, the wording related to implementation may be inconsistent with other provisions in TPL-001-5. Requirement R3, Part 3.5 has a similar identification and listing requirement regarding extreme events in the steady state portion of the Planning Assessment. However, there is no wording related to implementation in Requirement R3, Part 3.5.CenterPoint Energy recommends wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 and that references to implementation be removed.

CenterPoint Energy recommends that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

4.2.2.1. List System deficiencies and the associated actions needed to prevent the System from Cascading.

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

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

We do not agree with adding Parts 4.2.2.1 and 4.2.2.2 as they imply requiring implementation of actions needed to prevent the System from Cascading caused by extreme events – a criterion beyond the basic design and planning criteria. Adding these two parts essentially moves them into the “Steady State & Stability Performance Planning Events” table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listin g the 2a to 2j events under the Extreme Event table.

We strongly recommend the SDT to revert R4 to the currently approved version (TPL-001-4).

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1…..” Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

This overcomplicates the standard. The purpose of extreme event analysis is to understand the potential consequences of extreme events and to develop some ideas on how to address extreme events that result in cascading or instability. However, the current standard stops short of requiring corrective action plans, but defers to the PC/TP to make that determination based on the i) probability of occurrence, ii) level of impact, and iii) cost to mitigate or remedy. On the other hand, the purpose of planning contingencies (P1-P7) is to dictate minimum performance standards and require corrective action plans if performance does not meet the requirements of the standard. This clear distinction between planning contingencies and extreme event contingencies should be maintained for clarity and to avoid confusion. Therefore, to the extent it is desirable to modify the TPL standard to require corrective action plans for certain extreme events under certain situations, it would be better to move such events into the planning contingency category. That is, if it is desirable to require that corrective action plans be developed for three-phase faults with delayed clearing due to protection system failure if such events cause cascading or instability, then a P8 contingency should be created for this purpose, thus moving the three-phase fault with delay clearing out of the extreme event category and into the planning event category.   This maintains a clear distinction between extreme events and planning events.

Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

We would agree if the Standard Drafting Team would make it clear whether an implementation of a Corrective Action Plan is mandated in the Standard for Requirement R4, Part 4.2.2. While we agree that all mandated Corrective Action Plans (NERC defined term) should have an associated timetable for implementation (and possibly annual review of its status), we do not agree with requiring a timetable for implementation actions and annual review of implementation status if the Corrective Action Plan is not mandated.

If the Standard Drafting Team intends for these actions to be implemented, we will recommend using "Corrective Action Plan", which is a NERC defined term and eliminates the ambiguity in the requirement.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	

GTC does not support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2, for similar reasons to AZPS:

It is AZPS's understanding that, based on previous stakeholder input, the SDT determined that a Corrective Action Program (CAP) requirement was not appropriate for these extreme contingencies. AZPS respectfully submits that, although the verbiage has been revised, the obligation on entities as a result of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 essentially amounts to a CAP requirement. In fact, AZPS reads the requirements of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 as providing an even more rigorous obligation than other CAP requirements. For example, in Requirement R2.8, the CAP requires 3 actions: (1) a list of deficiencies, (2) the actions necessary to address these, and (3) an annual review for continued validity and status. Parts 4.2.2, 4.2.2.1, and 4.2.2.2 require: (1) a list of deficiencies, (2) the actions necessary to address these, (3) a timetable for implementation, and (4) annual review for continued validity and status. Thus, in comparing requirements for a CAP and the requirements set forth in Parts 4.2.2, 4.2.2.1, and 4.2.2.2, it is clear that, despite stakeholder input, Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are still requiring a CAP even though the contingencies to be addressed are extreme, unlikely to occur, difficult and expensive to address, and unlikely to significantly improve reliability. Finally, AZPS respectfully suggests that it is not cost effective to attempt to resolve system efficiencies as a result of such extreme events. Such activities have a very low cost/benefit ratio, and will result in the unnecessary expenditure of resources by registered entities. For these reasons, AZPS cannot support the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2 and, therefore, cannot support an associated timetable for implementation or annual review of implementations status

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy disagrees with the use of the term "implementation" in 4.2.2.1 and 4.2.2.2. Currently as written, a Planner is only required to conduct an evaluation of possible actions to reduce likelihood of Cascading resulting from extreme events. There is no further requirement for additional action other than what the evaluation must be comprised of. The use of the term "implementation" implies that an action other than the evaluation is required. The drafting team should consider adding additional language stating that implementation of said actions, are at the discretion of the Planner.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, and that an adjustable time frame should be considered during subsequent reviews.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	No
Document Name	

Comment

ISO-NE does not believe that it is appropriate to require the development of a timetable for implementation of a corrective action plan to address extreme events. Additionally, an annual review of the implementation status should not be required for extreme events.

Likes 0	
Dislikes 0	

Response

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	No
Document Name	

Comment

Extreme events should not need mitigation so a timetable is not needed.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect?

The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point.

The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	

Comment

The extreme events 2e-2h involve three-phase faults with delayed clearing. Three-phase faults are considered uncommon and very unlikely. If this involved single-phase faults with delayed clearing, then Oncor could agree with an associate time table since they are more probabilistic and feasible in terms of a capital project. The probability of a 3 phase fault along with delayed clearing of the fault is extremely unlikely. Additionally, an occurrence of this magnitude will generally involve shedding load and isolating the rest of the fault from the system.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

We believe that the proposed changes are confusing. It appears that the addition of part 4.2.2 requires a fix to prevent cascading for extreme events caused by non-redundant relaying components, while part 4.2.1 would continue to allow cascading for stuck breaker conditions. Why does part 4.2.2 require fixes for failure of non-redundant relaying components? Why isn't this requirement part of the PRC standards, but is instead proposed for standard TPL-001?	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	
CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect? The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point. The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	

CHPD does not agree with implementing a corrective action plan or an annual review of implementation status for preventing Cascading for Extreme Events. Extreme Events have a low likelihood of occurring and to mitigate these types of events would be costly and not provide much benefit due to their low likelihood of happening. The reference to a timetable, without a requirement to actually implement, may additionally provide a source of confusion. As an example, if a project would be needed seven years into the future, would it be appropriate for the timetable to reflect this seven year deadline, or should it reflect the system changes required to meet the seven year deadline? As a second example, if based on this analysis, system changes are immediately required to prevent Cascading, what should this timeframe reflect?

The second point of confusion is the language referencing the word “action”. Action is an undefined term, and thus is subject to multiple potential interpretations. Is the reference to action to mean that manual operator action is acceptable, or does action refer to a capital project to enact system changes to prevent the Cascading? This is unclear based on NERC and industry dialogue on this point.

The current language in TPL-001-4 only references an evaluation of possible **actions** designed to reduce the likelihood **or** mitigate the consequences of the event, not to determine a system change to fully mitigate the Cascading. There are two changes in the new proposed standard – the first is that the Cascading MUST have a fully mitigated solution (whereas the previous version also allowed a reduction of the likelihood) and the previous standard’s wording of action seemed to indicate the use of operator action, whereas the new standard’s discussion of timetables and implementation status is more consistent with the definition of action associated with the required system changes under the Corrective Action Plans.

Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	

Westar agrees with the the SPP Standards Review Group to recommend that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC concurs with R4 and the extreme events 2e-2h but believes that shunts should be added to the list of extreme events.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
The review should follow the designated Transmission Planner's existing processes that have already been developed. This review should be rolled into that process.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
In general we do not agree with imposing Corrective Action Plan requirement to prevent Cascading caused by extreme events, as it is a criterion beyond the basic design and planning criteria. However, we do agree with adding Parts 4.2.2.1 and 4.2.2.2 and require implementation of corrective action plans to mitigate reliability risks caused by failure of non-redundant Protection System components (only if the simulation indicates Cascading). Both FERC's Order 754 and NERC's Protection	

Systems Single Point of Failure - White Paper establish an event consisting of a three-phase fault followed by the failure of a non-redundant protection system component as a reliability concern that needs to be addressed. Moreover, the NPCC members have been mitigating these types of events for decades now, through the implementation of NPCC's regional criteria. Thus we strongly believe this should be a continent-wide requirement, as it helps improve the system's overall reliability.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

Since the requirements state there should be actions needed to prevent the system from Cascading and a timetable for implementation, Texas RE recommends requiring a Corrective Action Plan, which the NERC Glossary states is "A list of actions and an associated timetable for implementation to remedy a specific problem."

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

The SPP Standards Review Group recommends that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Steve Toosevich - NiSource - Northern Indiana Public Service Co. - 1	
Answer	
Document Name	
Comment	
See Joe O'Brien Comments for NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	
Document Name	
Comment	
MEAG Power supports the comments of Southern Company Services.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	

Document Name	
Comment	

In general we do not agree with imposing Corrective Action Plan requirement to prevent Cascading caused by extreme events, as it is a criterion beyond the basic design and planning criteria.

However, we do agree with adding Parts 4.2.2.1 and 4.2.2.2 and require implementation of corrective action plans to mitigate reliability risks caused by failure of non-redundant Protection System components (only if the simulation indicates Cascading). Both FERC's Order 754 and NERC's Protection Systems Single Point of Failure - White Paper establish an event consisting of a three-phase fault followed by the failure of a non-redundant protection system component as a reliability concern that needs to be addressed. Moreover, the NPCC members have been mitigating these types of events for decades now, through the implementation of NPCC's regional criteria. Thus we strongly believe this should be a continent-wide requirement, as it helps improve the system's overall reliability.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	
Document Name	
Comment	

To answer the question directly, the SRC does not believe it is appropriate to require the development of a timetable for implementation of a corrective action plan to address performance issues caused by extreme events. Additionally, an annual review of the implementation status should not be required for extreme events.

More importantly, the SRC does not agree with adding Part 4.2.1 or Part 4.2.2. The substance of Part 4.2.1 is already included in Part 4.5 of R4. The addition of Part 4.2.2, including Parts 4.2.2.1 and 4.2.2.2, is also inappropriate because these provisions could be read to require the TP and PC to prescribe actions to prevent the System from Cascading caused by extreme events – a criterion beyond the basic design and planning criteria. Adding these two parts essentially moves them into the "Steady State & Stability Performance Planning Events" table and a consideration for R2, R3 and R4 for which any unacceptable performance will require actions to mitigate the risks/reliability impacts. This is contrary to the intent of listing the 2a to 2j events under the Extreme Event table.

The addition of Parts 4.2.1 and 4.2.2 also raises a process question. Inadequacy in addressing Cascading caused by Extreme Events was not at all mentioned in Orders 754 or Order 786, nor was it presented in the final SAR for this project. Such addition appears to be a self-directed initiative that goes beyond the scope of the project, which may be regarded as a deviation from established standard development processes. We urge the SDT to revert R4, Part 4.2, to the currently approved version (TPL-001-4).

Note: ISO-NE does not support this comment.

Likes 0	
Dislikes 0	
Response	

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
TEP agrees that Requiement R4, Parts 4.2.2.1 and 4.2.2.2 should not mandate actual implementation of actions identified to prevent the System from Cascading. However, the language fail;s to get this point across. Requiring identification of actions to avoid a response along with a timeline to implementthe actions to mitigate the issue implies that these actions must be taken. R4 Part 4.2.2.2 further implies that an entity will be making progress to implement the corrective actions as it reviews the status of the mitigation each year. We agree that mitigation for an extreme event should not be required.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We understand that Parts 4.2.2.1 and 4.2.2.2 require the implementation of corrective action plans to mitigate Cascading caused by extreme events 2e-2h, when analysis concludes a mitigation plan is needed, even if a capital project is the only feasible action available. Corrective action plans should be implemented to prevent Cascading; however, this should be limited to protection system projects.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	

A corrective action plan should not be required for an extreme event. Corrective action plans, however, should be required for planning events described in 2e through 2h. While these events are currently included in the extreme events section of Table 1, and since corrective action plans should only be required for planning events, the events described in 2e through 2h should be moved to the planning events section of Table 1 while keeping the criteria to maintain system stability and to avoid cascading or uncontrolled islanding. The Table 1 steady state and stability performance requirements (such as equipment loading, voltage and stability) shall not apply.

ISO-NE does not think that the requirements as written mandate a corrective action plan.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, including for those System deficiencies that would require transmission and generation infrastructure upgrades. We propose the removal of references to implementation and timetables and instead focus these requirements on the identification of System deficiencies and associated preventive actions.

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	No
Document Name	

Comment

GTC agrees that there should not be a mandate of an actual implementation of actions. However, the current language leaves too much room for interpretation and suggests that a CAP is required. We suggest languae similar to Requirement 3.5.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
We understand that Parts 4.2.2.1 and 4.2.2.2 require the implementation of corrective action plans to mitigate Cascading caused by extreme events 2e-2h, when analysis concludes a mitigation plan is needed, even if a capital project is the only feasible action available. Corrective action plans should be implemented to prevent Cascading; however, this should be limited to protection system projects. The Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, calls for (1) studies to be performed; (2) evaluation of actions (i.e. solution) that would reduce or mitigate (i.e. solve) the identified deficiency; (3) timetable for implementation of the solutions; (4) annual review; and (5) listing of the implementation status. Therefore, the Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading. Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
The requirements to have an implementation timetable and annual review, particularly of the "implementation status" suggests that 4.2.2 is mandating a Corrective Action Plan. If this is not the intent of 4.2.2.1 and 4.2.2.2, it must be clarified and explitcity indicated that implementation of a Corrective Action Plan itself (capital project or otherwise) is not required.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	

Answer	No
Document Name	
Comment	

There appears to be very little difference between 4.2.1 and 4.2.2 other than making a list and establishing an implementation timetable that would be meaningless if there is no intent to implement the solution. The current TPL-001-4 wording is sufficient unless there is a desire to require development and implementation of a Corrective Action Plan for certain events and circumstances, in which case, as previously suggested, the contingency should be moved from the extreme event category to a planning contingency category. Otherwise the wording in the current standard regarding extreme events that are found to result in cascading and/or instability should not be modified.

Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	

We believe that the language in proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2 can be interpreted to mean that an actual implementation of actions and/or a capital project(s) is required.

Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	

CenterPoint Energy agrees that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2 should not and do not mandate actual implementation of actions identified in the analysis as being needed to prevent the System from Cascading. However, CenterPoint Energy disagrees with the wording in Requirement R4, Parts 4.2.2.1 and 4.2.2.2 related to implementation. As discussed above, CenterPoint Energy recommends wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 related to extreme events for the steady state portion of the Planning Assessment.

CenterPoint Energy recommends that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading.

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

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

We agree that Parts 4.2.2.1 and 4.2.2.2 should not mandate actual implementation but disagree that the language for 4.2.2.1 adequately conveys this. Although the drafting team made its rationale clear for the additional proposed actions for the extreme events 2e-2h, SCE advocates that this language confuses the intent and will create compliance ambiguity in the future. SCE proposes that the drafting team remove sub-requirement R4.2.1 and R4.2.2 (and the underlying R4.2.2.1 & R4.2.2.2) entirely. This change will significantly reduce the confusion for the intention to not obligate entities to actually implement actions identified, and it will keep the compliance obligation clear in the future. Entities should look into actions that may reduce exposure or impact for 2e-2h in the same manner as other extreme events.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn,

Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments that part 4.2.2 and all the subparts under it for R4 are not required at all.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Requirement 4.2.2 only requires “an evaluation of possible actions designed to prevent the System from Cascading”. ITC believes that if the occurrence of an extreme event (2e-2h) were projected to cause cascading it should mandate actual implementation of actions identified as needed to prevent the System from Cascading.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
No. This aspect of the standard does not appear to meet the 'Clear Language' criteria in NERC's Standards Quality Review 'QR' Checklist because the requirement language as written does not assure that entities will be "able to arrive at a consistent interpretation of the required performance.	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The words utilized in this question seem to imply that a Corrective Action Plan may not be required. However, the use of the phrases "associated timetable for implementation" and "implementation status" makes the intent misleading. It is unclear how this differs from Requirement 2.7 which states "Corrective Action Plan(s) addressing how the performance requirements will be met." Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase "excluding extreme events 2e – 2h in the stability column".	
Likes 0	

Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The “timetable” implies that we are going to fix it but as stated above. WAPA does not believe that there will be a commensurate improvement in system reliability and we have no directive from FERC that actions should be required.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
The requirement calls for listing the deficiencies, the actions needed to prevent the system from cascading, the associated timetable for implementation, and then be reviewed annually with an implementation status. Having an implemention status with a timeline implies that the recommended implementation plan needs to be put into effect. If a capital project is the only feasible action, then it can be interpreted that implementation of the capital project is needed.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
The language indirectly mandates implementation of construction for system deficiencies resulting from extreme events via a timetable. Otherwise, what is the purpose of developing a timetable if the intent is never to correct the deficiency? We recommend that the SDT remove the timetable	

language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted."

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

No, AZPS does not, based on its review of the language, agree that the Parts 4.2.2, 4.2.2.1, and 4.2.2.2 “should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading.” In fact, its comparison of the language to the language of those requirements associated with a mandatory CAP indicates that the language and obligations under Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are actually more robust and stringent. This comparison is provided above in Question 1. For these reasons, AZPS does not agree with the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. AZPS submits that these requirements together amount to an actual implementation requirement, and that the language is consistent with a required/ mandatory CAP. Irrespective to whether or not a Transmission Planner believes a capital project is required to be implemented by Parts 4.2.2.1 and 4.2.2.2, the compliance will be determined by the language in the standard. If the language in Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are essentially the same as that for a CAP, the requirement is essentially equivalent to CAP.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, to clarify the intent stated in this question, AZPS recommends the following revisions to the proposed language for Parts 4.2.2, 4.2.2.1, and 4.2.2.2:

4.2.2 If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e -2h

4.2.2.1 Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.

4.2.2.2 Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

The way it reads seems to imply an implementation of actions is required and that action could result in a capital project. If the only feasible means to prevent a cascading event is a capital project then this seems to be a meaningless exercise if there is no requirement to implement it.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

The language of these proposed subrequirements does not suggest that actual implementation is optional. The components of a Corrective Action Plan as defined in the NERC Glossary are clearly required by the proposed 4.2.2.1. 4.2.2.2 contains an expectation that the actions needed to prevent the cascading would be implemented at some point. Again, we question the point of devising preventive actions and an associated timetable, and performing an annual review of implementation status for mitigating actions that are supposedly never to be "required."

In addition, AEP does not agree that Correction Action Plans would be justified or necessary in every case. Considerations such as the nature and/or extent of any potential cascading should be a factor in determining whether or not a CAP is necessary, but as currently written, the obligation does not allow such engineering judgment. If mitigation is truly not required, then the language of R4.5 in TPL-001-4 is all that should be necessary.

Once again, as stated in our response to Question 1, AEP believes that pursuing Corrective Action Plans as part of R4, Part 4.6 goes beyond the scope of the current SAR.

Please note that AEP has chosen to vote Negative on TPL-001-5, in large part due to our objections as provided in our response to Questions #1 and #2.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	No
Document Name	

Comment

The Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, calls for (1) studies to be performed; (2) evaluation of actions (i.e. solution) that would reduce or mitigate (i.e. solve) the identified deficiency; (3) timetable for implementation of the solutions; (4) annual review; and (5) listing of the implementation

status. Therefore, the Requirment (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that requiring an implementation plan and timetable is similar to a corrective action plan and is being mandated. Until the studies are done, it can not be determined if any capital projects were included. In general, the utility will determine whether or not to address an issue based on risks and consequences of the event.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Requirement parts 4.2.2.1 and 4.2.2.2 require Responsible Entities to create associated actions and a timetable for implementation. Compliance enforcement staff could interpret the requirement such that a documented action is required to be implemented.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP agrees TPL-001-5 should not mandate actual implementation of a Corrective Action Plan. However, the current language of 4.2.2.2. leaves too much of a gray area that is open for interpretation as mandating actual implementation. SRP recommends removing 4.2.2.2. altogether. The impacts of extreme events 2e-2h in the stability column, and the actions required to prevent the System from cascading are addressed by 4.2.2. and the first part of 4.2.2.1. in every annual Planning Assessment. Requiring a review "for continued validity" is redundant, and requiring a timetable for implementation or a review of implementation status is unnecessary for a NERC Reliability Standard.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

MH believes the language in 4.2.2.1 and 4.2.2.2, as written, mandates construction to prevent Cascading for extreme events. The wording of this question is confusing "... should not and do not mandate ...". If the first sentence is intended to breakup as follows:

Do you agree that …….. should not mandate ……? Answer - Yes

Do you agree that……… do not mandate …………..? Answer - No

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

The way it reads seems to imply an implementation of actions is required and that action could result in a capital project. If the only feasible means to prevent a cascading event is a capital project then this seems to be a meaningless exercise if there is no requirement to implement it. Permitting the implementation of capital projects to be optional when it is the only feasible solution subjects the utility to the possibility that the state commissions might view the capital project (expenditure) as not necessary for reliability given that the justification is based on an extreme event(s).

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
Oftentimes the capital project may be a relay upgradeproject which is relatively low cost compared to the benefits.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Oftentimes the capital project may be a relay upgrade project which is relatively low cost compared to the benefits.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
In addition to our comments under Q1, we believe that analyzing system performance when subject to "Extreme Events" is meant to provide a sense of where instability and/or Cascading could occur for the PC and/or TP to assess what actions could be developed to mitigate or reduce the potential impact. Such actions generally involve positioning the BES, adjusting outage plans, implementing operations strategies, developing a safe posture and preparing for resiliency plans, but not any capital investment projects. Note that this does not preclude the responsible entity from implementing any of these actions in its sole discretion, but it should not be mandated. Capital projects to address operational circumstances should not be mandated in a TPL standard. Further, requiring capital projects would exceed the scope of FERC Order 754 and 786 as well as the SAR. **Note: ISO-NE does not support this comment.**	

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

ALAN ADAMSON - New York State Reliability Council - 10

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

The SPP Standards Review Group recommends that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees that no corrective action plan should be required for extreme events 2e-h in accordance with the actions the FERC and FRCC have agreed to in XXXXXX (need reference from Fabio). Therefore there is no need for any wording regarding implementation.	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Westar agrees with the SPP Standards Review Group to recommend that the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
We believe implementation of actions should not be mandated. In addition, because the actual implementation is not mandated, the timetable for implementation should not be required either.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Per our (JEA's) comment for Question #1, part 4.2.2 and all the subparts under it for Requirement R4 are not required at all. Hence this question #2 becomes moot for an extreme event. However for the Planning Event P5 with the added clarification with footnote 13, new situations can be unearthed in the new studies which may require an implementation timetable and an annual review of the implementation status for a capital project as part of the Corrective Action Plan	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes. SCL agrees with simulation of extreme events to develop awareness of the constraints, if any, of the BES. Implementing actions for extreme events is not necessary, because the corrective action plan can be costly and not produce much benefit due to the low frequency of extreme types of events happening.	
Likes 0	
Dislikes 0	

Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
If small system upgrades can be implemented to keep the system from cascading, we believe that these upgrades should be pursued in a timely manner. But as mentioned above, why does part 4.2.2 require fixes for failure of non-redundant relaying components? Why isn't this requirement part of the PRC standards, but is proposed for standard TPL-001?	
Likes 0	

Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Please refer to comment for Question 1.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
CHPD agrees that the requirement should not mandate implementation of actions identified as needed to prevent the System from Cascading. CHPD agrees that a capital project should not be required to prevent Cascading as these Extreme Events have a low likelihood of occurring and are costly to mitigate.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE agrees that the current language does not mandate actual implementation. However, Texas RE would support requirements mandating implementation of the actions determined by the PC and TP to reduce the likelihood of Cascading consistent with regional planning processes.

Additionally, Texas RE would support the development of a Corrective Action Plan that included a capitol project designed to mitigate Cascading if that were the only option. Generally capital projects endure scrutiny by the planning processes in the Texas RE region.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
If the PC decides to implement a Corrective Action plan to address an extreme event, they should be allowed to modify it, but they shouldn't be held to meeting performance requirements. Maybe the change is lower in cost and limits the extent of Cascading.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
We agree with the omission, however, we disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	
If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The planned system should always meet the performance requirements in Table 1 in any Planning Assessment that is performed. To the extent a Corrective Action Plan is developed for issues identified in one Planning Assessment and the issues go away in subsequent Planning Assessments due to changes in load forecasts or other drives of the original issue, elimination or modification of the Corrective Action Plan in the subsequent Planning Assessment should certainly be allowed, but the language above that states "the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments" seems unnecessary since the Table 1 requirements apply to all Planning Assessments.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
We support mandating the implementation of Corrective Action Plans if they are limited to protection system modifications.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	

As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

See MidAmerican Energy's comments. There should not be a requirement to mitigate extreme events.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	

Comment

The proposed language of Part 4.2.1 and 4.2.2 in TPL-001-5 is an addition, not an omission. We disagree with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance

Answer	No
Document Name	

Comment

It is appropriate to meet performance requirements in subsequent planning assessments

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

It is appropriate to meet performance requirements in subsequent planning assessments.

Likes 0	

Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Analysis of extreme events for awareness of BES constraints is sufficient, so meeting performance requirements for subsequent planning asssessment is not necessary.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
For extreme events, the planned System should not be required to meet the performance requirements of Table 1.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that the omission in 4.2 is necessary as there are not performance requirements in the Table for Extreme Events. BPA believes the focus should be all about reducing the likelihood, not preventing it. We do not agree with separating out extreme events in 2e-2h, everything should be included in 4.2.1 BPA believes that 4.2.1 should be modified to remove "excluding extreme events 2e-2h in the stability column".	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP agrees with the omission but we are not persuaded that this omission would excuse a TP or PC from implementation of what may very well be construed as Corrective Action Plans under the proposed R4.2.2.	
Likes 0	

Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

While we agree that there should be an omission, the use of the phrases “associated timetable for implementation” and “implementation status” in R4.2 gives the perception that capital projects would be required. It is unclear how this differs from Requirement 2.7 which states “Corrective Action Plan(s) addressing how the performance requirements will be met.” Suggest that Part 4.2.2 and its sub Parts can be struck. If there is a corrective action plan required, as implied by 4.2.2.1, then this event should be listed in Table 1 P5 instead of the Extreme Event Table. Also, in 4.2.1, strike the phrase “excluding extreme events 2e – 2h in the stability column”.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	Yes
Document Name	

Comment

We concur with the omission.

We do not believe that actions to mitigate Cascading are required for meeting the performance requirements in Table 1 when subject to Extreme Events. The continued omission of such a requirement in R4 is justified.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

Yes. We agree that a requirement to ensure that Cascading does not occur in subsequent Planning Assessment given extreme events 2e-2h in the stability column should be omitted. Further, to include a requirement such as this would be identical to a Corrective Action Plan.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
ISO-NE agrees that a corrective action plan should not be required for an extreme event. The 2e through 2h events referenced in Requirement R4, Part 4.2.2, however, should be planning events and, accordingly, corrective action plans should be required for them.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
TEP agrees that extreme events do not need the same level of requirements as Planning Events.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Consistent with our comments under Q1 and Q2, we do not believe that actions to mitigate Cascading are required for meeting the performance requirements in Table 1 when subject to Extreme Events. The continued omission of such a requirement in R4 is justified.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
The omission as proposed in Requirement R4, Part 4.2 seems to allow a little more flexibility in our interpretation in how we meet the performance requirements in Table 1 for our Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
We believe that requirement 2.7 would cover system performance for the R4 requirements.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
To confirm, in summary R4.2 for extreme events has been re-drafted in R4.2.1. to exclude the new expanded definition of protection system failure events from the evaluation covered in R4.2.2. which specifically applies additional requirement to the new protection system failure events. Based on this interpretation, this is an acceptable omission for those non-protection system failure events. However, CHPD feels Corrective Action Plans should not be required to mitigate all Extreme Events (including protection system failure) because it would be costly and have little benefit as Extreme Events have a low likelihood of happening. Thus, these Extreme Events are studied for system awareness and determining the constraints of the system.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

ALAN ADAMSON - New York State Reliability Council - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Part 2.7 is referring to the planning events Table 1 which has performance requirements for maintaining a normal system. Part 4.2 is referring to the extreme events, which does not have performance requirements in Table 1. A similar requirement is not needed because Part 4.2 says to perform studies to assess the impact of extreme events and conduct an evaluation of possible actions that could reduce the likelihood, mitigate, or prevent Cascading that occurs due to an extreme event in the list.

Likes 0	
Dislikes 0	

Response

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g*., sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team provide more clarity in reference to the example in Footnote 13 (a) to refer to alternate performance to achieve electrical clearance rather than the relay to electrical quantities in which it may cause confusing on how it's interpreted.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
ISO-NE suggests revising footnote 13-1 to read as follows: 1. A single protective relay that is relied on for Normal Clearing times, without an alternative that provides comparable Normal Clearing times. A protection system may rely on a single protective relay that does not respond to electrical quantities such as a sudden pressure relay. Therefore, having the footnote refer to only relays that respond to electrical quantities may allow the failure of other critical relays to be ignored.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

We believe the SDT should specify the actions taken by a single protective relay instead of identifying individual Protection System components for this standard. The reference to “an alternative that provides comparable Normal Clearing times” is confusing when associated with sudden pressure relays and included as a condition for non-redundant components of a Protection System.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
We agree with the concept as layed out in the question, which limits the scope of what needs to be studied. However, the bullet points do not match up with the documents reviewed (13.1 vs 13.a).	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Remove “e.g. sudden pressure relaying” text	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	

Please clarify what constitutes an "alternative" relay. Is an "alternative" relay only referring to a relay that does not respond to electrical quantities? Further, what if alternative relay does not provide the same clearing time as primary relay (e.g., the alternate relay is an impedance relay with longer Zone 2 timer, or alternative relay is overcurrent relay, while primary relay is impedance relay). Is the alternative relay then considered as 'redundant', and therefore footnote 13 does not apply? We do not believe it is fully clear of what constitutes "comparable" in the context of comparable Normal Clearing times in Table 1 Footnote 13 Part 1. We further do not believe that it is fully clear what is required for a relay to be "monitored." Is it required that alarms are centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)? Cf. 'Single Points of Failure TPL-001 Technical Rationale' document. Suggest adding parenthesis to clarify that sudden pressure relays are excluded. "[a] single protective relay which responds to electrical quantities (without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying)". As it is written currently, "sudden pressure relaying" would seem to respond to electrical quantities.	
Likes 1	PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We agree with the attempt to clarify Table 1 Footnote 13 a. However, it is not clearly understood what is meant by the second part of the proposed statement "without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying". For example, does this mean that if an alternative that provides comparable Normal Clearing times exists, then the single protective relay that responds to electrical quantities is not considered "non-redundant" (and therefore would not be considered a non-redundant component of a Protection System)?? Recommendation is to re-word the sentence to make it absolutely clear.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the ", e.g. sudden pressure relaying" text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit's functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions versus normal transformer differential protection.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	No
Document Name	

Comment

Suggest adding parenthesis to clarify that sudden pressure relays are excluded.

"[a] single protective relay which responds to electrical quantities (without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying)". As it is written currently, "sudden pressure relaying" would seem to respond to electrical quantities.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No

Document Name	
Comment	
NVE agrees with the intent of Footnote 13a, but would like to see clarification with the wording especially on terms (i.e. “comparable”). Perhaps, a defined term should be created similar to the WECC regional definition of ‘Functionally Equivalent Protection System’. Footnote 13a, could then be re-written to “[a] single protective relay without a Functionally Equivalent Protection System.” This would then cover multiple cases including the example provided in the Technical Rationale between the differential relay and sudden pressure relay.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated. Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions. The difference between Sudden Pressure relay trips and regular protection system trips may avoid equipment damage, but may not have any impact on instability, uncontrolled separation, or cascading.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP seeks clarity on the intent of the use of the term “comparable” relative to the NERC Glossary Term Normal Clearing Time. Would a Protection System designed with a communication-aided primary relay and a step-distance backup relay for the same BES line be considered non-redundant per footnote 13a?

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy agrees that other relay types such as sudden pressure relays can respond just as quickly to fault conditions and should be counted as a redundant component. Dominion Energy does not understand the rationale for limiting this to just the single protective relay and not other protective elements. For example, would it not be possible that the sudden pressure relay uses a separate trip path that would create the redundancy necessary? Should that not count towards the redundancy?

Likes 3	Luiggi Beretta, N/A, Beretta Luiggi; PSEG - PSEG Fossil LLC, 5, Kucey Tim; PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

A sudden pressure relay doesn’t respond to electrical quantities. It is not even a component of a “Protection System,” which is the premise of the lead sentence of Footnote 13: “For purposes of this standard, non-redundant components of a *Protection System* to consider are as follows:” The drafting team may be confused because sudden pressure relays are included in PRC-005-6 – Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance. But as its title indicates, “Automatic Reclosing” and “Sudden Pressure Relays” are distinct from “Protection System.”

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	No
Document Name	
Comment	

The item label in TPL-001-5 is Footnote 13 1, not Footnote 13 a. We agree with having a single protective relay item in Footnote 13 and acknowledge that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

Likes 0	
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	
Comment	

Footnote 13 should indicate that single protective relay applies to a relay unit and not a relay element. Multiple relay elements within a single relay unit (e.g., multiple elements in a common digital relay, etc.) are not redundant since a common failure (e.g., power supply) could impact all relay elements within the relay unit.

Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	
Comment	

CenterPoint Energy agrees with including Table 1 Footnote 13 a., “[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying.” Presently, only Sudden Pressure Relaying meets this wording based on a NERC System Protection and Control Subcommittee report (Sudden Pressure Relays and Other Devices that Respond to Non-Electrical Quantities - SPCS Input for Standard Development in Response to FERC Order No. 758, December 2013) and the approved NERC Standard PRC-005 Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance. The proposed wording by the SDT for Table 1

Footnote 13 allows other types of relays that do not respond to electrical quantities to be added in the future, when approved, eliminating the need to revise this requirement in TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
This question is not worded very clearly. We believe the question is asking whether we agree that the language added should only apply to 13a and not to 13 b, c, or d (which we agree with). However, as written, it is very confusing since the quotes include the term "single protective relay" and then we are asked if we agree to "its limitation to only the specific single protective relay".	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
WAPA agrees with having a single protective relay item in Footnote 13 and acknowledges that contemporary protective relay units normally perform multiple fault protection functions. However, we suggest removing the “, e.g. sudden pressure relaying” text for two reasons. First, sudden pressure relaying does not provide full redundancy of a transformer protection relay unit’s functionality, but the present wording gives the impression that sudden pressure relaying will always provide full transformer protection relay redundancy. Second, the sudden pressure relay wording is somewhat confusing and can appear to identify sudden pressure relays as a type of protective relays to be evaluated. Note: Equipment protection should not be confused with the TPL-001-5 reliability objective of providing adequate transmission capability to meet TPL-001-5 criteria avoiding instability, uncontrolled separation, and cascading. Sudden Pressure relays may be used as an additional protection to avoid equipment damage by removing a transformer quickly under specific conditions. The difference between Sudden Pressure relay trips and regular protection system trips may avoid equipment damage, but may not have any impact on instability, uncontrolled separation, or cascading.	
Likes 0	

Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: "[a] single protective relay which responds to electrical quantities, without an alternative that responds to non-electrical quantities and provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying"	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: "[a] single protective relay which responds to electrical quantities, without an alternative that *responds to non-electrical quantities and* provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying",	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
The Technical Rationale provides an example of fault in a transformer and the use of a sudden pressure relay. However, this is of no practical value since the Transmission Planner still has to account for the fault outside of the transformer tank and the sudden pressure relay will not protect against that. There is no benefit of adding this language related to an alternative device.	
Likes 0	

Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
However, the following wording would be clearer: "[a] single protective relay which responds to electrical quantities, without an alternative that responds to non-electrical quantities and provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying"	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA agrees. BPA believes that there is inconsistency between the redlined and clean versions of the standard. The Redlined version identifies Footnotes correctly as 13 a,b,c,d; Clean version shows 13 1,2,3,4. Please correct.	
Likes 0	

Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	

Comment
SNPD does not have additional comments.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment
No Comments

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	

Comment
If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated. CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document “Protection System

Reliability – Redundancy of Protection," as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated. CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document "Protection System Reliability – Redundancy of Protection," as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
The specific explanation for a single protective relay (alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying.) seems to provide more clarity on how we can include these relay protection failure scenarios within our Stability Analysis contingencies.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE agrees with including protective relays in Footnote 13. As stated in its comments for the Standard Authorization Request (SAR), Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. The NERC Glossary definition states: “Protective relays which respond to electrical quantities” while Footnote 13 states “a single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying.” Texas RE recommends Footnote 13 align with the NERC Glossary to avoid confusion. Texas RE noticed Footnote 13 is listed in number format, not letters as questions 4, 5, and 6 indicate on this form.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	

Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

If the scope was broadened to include other elements associated with the Protection System (like PTs, CTs, Comm gear, etc.) the contingency list would be overbearing and would not add any benefit to the analysis. Failure of these other elements would produce redundant results to protection system failure events which are already evaluated.

CHPD finds this clarification helpful in explaining the expectation of the applicable requirement, but would also note that this definition of non-redundant components is different than the other NERC definitions of non-redundant components addressed in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.

Likes 0	
Dislikes 0	
Response	

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, “which is not monitored or not reported”, and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?	
Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
It is questionable how monitoring will help in the case of a single protection channel. If the monitoring indicated the channel was not available, would the transmission line be taken out of service? The problem is how reliable is the monitoring? The concern is the case when a fault occurs and the single communication system fails. If monitoring is secure and the system can handle an outage of the line to fix the communication system, it’s not a bad strategy to save cost.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP seeks clarity regarding the intent of the use of the terms “not monitored or not reported.” Is the intent of the SDT to align with alarming and monitoring functions outlined in PRC standards? Furthermore, it appears that if the components are either monitored OR reported (but not both) it would meet the intent of Footnotes 13b & c. As proposed in the proposed draft, an entity would only have to monitor but not have to report or annunciate for the abnormal conditions specified in Footnote 13a & 13b.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	

The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

NVE would like to see more clarification with monitoring and reporting. The frequency and definition of the monitoring should be more specific. If an entity inspects a substation once a year, and considers that as monitoring the DC supply, that does not seem like an effective method for excluding a study of a non-redundant DC supply since the DC supply could then fail within the year period and wouldn't be known until the next inspections. Adding some wording that defines monitoring and reporting would eliminate any confusion. An example would be "alarming for failure within 24 hours of detection to a location where corrective action can be intitiated."

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5

Answer	No
Document Name	

Comment

Although supportive of the stipulation, LES recommends the following change to Footnote 13c to better clarify expectations.

A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported***, either directly or indirectly,*** for both low voltage and ***for interruption of the station DC supply by the main protective device.***

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
The terms “monitored” and “reported” need to be fleshed out more. For example, communication circuits can be monitored continuously, daily, weekly, or monthly. What level of monitoring qualifies? The term “reported” could be to an annunciator panel in a station that may be monthly reviewed or it could be to an operations center that is staffed 24/7. See PRC-005-6 Tables 1-2, 1-4, and 2 for examples of how these terms can be used more clearly. We suggest the SDT consider defining these terms as they are used in multiple standards now.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Using the term "reported" is confusing given the expectation that remediation of a failure status is "prompt". Other standards have already established terms for what is considered "monitored", such as PRC-005. Can we not rely on these established concepts?	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	

Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
With regard to communication-assisted protection system where a communication signal is required for tripping and normal clearing, this should be considered a single-point-of-failure regardless of whether or not it is monitored. So the answer is NO for Footnote 13.b. With regard to DC supply, since there is some redundancy between the battery and the battery charger, the answer is YES for Footnote 13.c, but there should be additional language that requires separate protection (fuse or circuit breaker) for the battery and the battery charger so once can operate without the other.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
The PC or TP will be able to determine if communication systems and DC supplies are monitored but it will not know if they are reported. It is presumed that if they are monitored they are reported.	

Please consider eliminating the requirement to monitor and report “open circuit” conditions, since such conditions would be tested and maintained per NERC Reliability Standard PRC-005 ‘Protection System, Automatic Reclosing, and Sudden Pressure Relaying’. We believe that preventive maintenance per PRC-005 provides reasonable and sufficient assurance for detection and handling “open circuit” conditions.

Likes 0	
Dislikes 0	

Response

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis

Answer	No
Document Name	

Comment

Footnote 13 is numbered and not lettered. GTC feels that "which is not monitored or not reported" is not clearly defined. There needs to be a timing frequency as to how the equiment is monitored and when an action will be required to mitigate/correct the problem.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

We agree with the concept as layed out in the question. However, the bullet points do not match up with the documents reviewed (13.2&3 vs 13.b&c).

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

The above question misidentifies items 2 and 3 of footnote 13 as letters “b” and “c.” We concur that the meaning of “not monitored or reported” regarding a single communications system or dc supply associated with protective functions does convey an expectation that operating personnel who are monitoring such equipment will initiate field remediation activities to mitigate a failure. However, the proposed footnote should limit the inclusion of these Protection System components to only critical sites and at the discretion of the PC or TP.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	

Comment
ISO-NE agrees that a monitored dc supply is sufficient to achieve prompt remediation to address the failure as described in Footnote 13-3. ISO-NE suggests modifying 13-3 to read as follows: 3. A single dc supply associated with protective functions necessary for Normal Clearing, and that single station dc supply is not monitored or not reported for both low voltage and open circuit; The proposed language above is more consistent with 13-2.

Likes 0	
Dislikes 0	

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	

Comment
We agree with the inclusion of this wording, with the exception of c. “…for both low voltage and open circuit.” Our DC supplies are monitored, but only for voltage level and not for open circuit.

Likes 0	
Dislikes 0	

Response

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
The item labels in TPL-001-5 are Footnote 13 2. & 13 3., not Footnote 13 b. & 13 c. We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
We agree with the inclusion of this wording, with the exception of c. "…for both low voltage and open circuit." Our DC supplies are monitored, but only for voltage level and not for open circuit.	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
The SPCS concluded that analysis of communications systems with regard to single points of failure did not pose enough of a risk to warrant addition in footnote 13. This assessment was based on SPCS efforts over the years studying blackouts/significant events and their causes. Communication system failures were not a causal factor in the significant events studied by the SPCS. Failures of relays and auxiliary relays have been causal in significant events. We recommend removing communication systems from footnote 13 in the revised standard.	
Likes 0	

Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Note: In the "Redline to Last Approved" version of the standard that is posted on the project page, the subparts of Footnote 13 are numbered, not lettered.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
We agree with having a single communications system item in Footnote 13. However, we suggest limiting applicable communications systems to those that were installed specifically to assure crucial Normal Clearing times. We agree with having a single DC supply associated with protective functions item in Footnote 13 and with exempting those single DC supplies that are monitored or report both open voltage and open circuit.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy agrees that the inclusion of Table 1 Footnote 13 b. & c. stipulation, “which is not monitored or not reported,” conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment. However, instead of utilizing this newly drafted wording for monitoring, CenterPoint Energy suggests using the wording that is included in the Standard Authorization Request (SAR) as follows: “with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated).” This wording in the SAR related to monitoring of Protection Systems has been previously approved by stakeholders and regulators for NERC Standard PRC-005, Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: MISO does not support this comment.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.	
Likes 0	

Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	

Comment

If the communication system or DC supply is being monitored, then it is not a single point of failure because the monitoring would have to be lost and an equipment failure would have to occur.

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
As stated in its comments regarding the SAR, Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. Texas RE recommends Footnote 13 align with the NERC Glossary term as well as the monitoring and alarming attributes specified in PRC-005-6 to promote consistency.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We recommend treating trip coils in the same fashion as protective relays, communication systems and DC Supply, meaning that a single trip coil which is monitored and reported meets the redundancy requirement.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
The language in Table 1 Footnote 13-4 that addresses single control circuitry is unclear. Therefore, ISO-NE proposes revising the language as follows: 4. Any single control circuitry from the dc supply through the relay to the trip coil of the circuit breakers or other interrupting devices.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe the inclusion of interrupting device trip coils could impact many elements and be outside the intent of a single point of failure analysis. We believe the analysis should only be limited to auxiliary relay components.	
Likes 0	

Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
A more explicit definition of the control circuitry is needed. Does this include the cables, auxiliary relays, cable routing? The cables are routed in a controlled environment, therefore have less exposure. Lockout relays and trip coils are monitored for integrity of the trip coil path. Does this eliminate the need for separate control circuitry? Our interpretation is that a shared controlled circuit as defined would need to meet clearing time concerns as defined, each relay function requiring a separate control circuit.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
Non-redundant components should not consider a single trip coil. Consaidering the trip coil goes beyond non-redundancy of the protection system, in essence the SDT is considering non-redundancy of circuit breakers or other interrupting devices. Please clarify what constitutes “control circuitry.” Please consider adding text from (or referring to) relevant technical rationale document(s), which describes the applicable portions of a “Protection System” as defined in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	

Comment	
We recommend treating trip coils in the same fashion as protective relays, communication systems and DC Supply, meaning that a single trip coil which is monitored and reported meets the redundancy requirement.	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We feel that it is possible that the revised Table 1 Footnote 13 d helps to identify what constitutes all of the elements of, “A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.” However, considering the complexities of Footnote 13 d, sample, or representative protection system diagrams and circuitry that would constitute examples of non-redundant components of a Protection System would be helpful. Such diagram(s) are recommended, and would provide clarity in a similar fashion as the diagrams provided in the NERC BES Reference Document.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Monitoring trip coils will ensure that the circuit breaker will trip but as the drafting team points out, it will not ensure that all the electromechanical lockouts (#86) nor the tripping auxiliary relays (#94) will work properly. While it is correct that PRC-005 monitoring does not include electromechanical lockouts (#86) nor tripping auxiliary relays (#94), these components are tested independently as prescribed by PRC-005 to ensure they are working properly. If the transmission system should be designed to be resilient against electromechanical lockout failure or tripping auxiliary relay failure, it doesn't make sense to include testing requirements under PRC-005. Conversely, if we require the industry to test these components, it is extraneous to build the system to be resilient to failure of these components. The number of low-probability events that must simultaneously occur already stretches the bounds of what is reasonable to justify grid expansion (through redundancy or other projects). PRC-005 is already a mitigating activity to the probability of those events and trip coils that are monitored in real-time should be excluded from footnote 13 d.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

The wording in this bullet is somewhat confusing. We recognize that a, b, c, and d in footnote 13 are an attempt to adapt the definition of Protection System, and the original text was "DC control circuitry associated with protective functions through the trip coils…". However, now that we have added "single" to the phrase – it is a single control circuit, or a single portion of a control circuit, to which we are referring? "Single control circuitry" appears to be a mix of singular and plural contexts, or even a mix of a context which is specific to a quantity with one which is inherently both singular and multi-faceted. The SPCS report, page 11, recommended using "(3) DC control circuitry associated with protective functions…" which we would take to mean "the intended outcome of the DC control circuit associated with a protective function, or associated with multiple protection functions, does not come to pass". In this way, it can be adapted to any circuit design by the engineer, applying sound engineering judgment, to determine whether there are any portions of that circuit which may result in significant "failure to perform" outcome. With the term "single" the sentence could be read to mean "the entirety of the control circuit, including every component" since "circuitry" is both singular and multi-faceted in its use. Also, in other standards, DC control circuitry is inclusive of certain auxiliary relays, but this is not clear in the statements added. We suggest either sticking with the original language recommended from the SPCS or using one of the adaptations we've written above to clarify that the engineer should review the components (segments, sub-sections, branch connections – select as you see fit) of each control circuit to look for portions of any circuit associated with a protective relay whose failure could result in more circuit performance failures than just that of one protective relay.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

The scenario described in Footnote 13d is the exact scenario studied under Category P4. Failure of a single trip coil in a breaker would result in the exact same scenario as a stuck breaker during a fault. Studying a P4 event and a P5 event for Footnote 13d would result in the same contingency. NVE feels that Footnote 13d should be removed and Footnote 10 be modified to include scenarios such as single trip coils.

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuitry item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
As similarly requested in previous comment periods, AEP once again requests additional clarification of footnote 13.4 regarding the phrase “Including the trip coil(s) of the circuit breakers or other interrupting devices.” For example, in the data request associated with FERC Order 754 (Single Point of Failure on Protection Systems), local breaker failure protection was allowed to be modeled in cases of non-redundant trip coils. In addition, the NERC System Protection and Control Task Force Technical Paper ‘Protection System Reliability Redundancy of Protection System Elements’, provides the following clarification: “A properly designed breaker failure scheme meeting all the requirements of the TPL standards and the proposed Protection System redundancy requirements could be used to overcome a breaker with only one trip coil or two trip coils operated in parallel.” As a result, AEP requests the previous clarification text be added to footnote 13.4 : **“A properly designed breaker failure scheme meeting all the requirements of the TPL standards and the proposed Protection System redundancy requirements could be used to overcome a breaker with only one trip coil or two trip coils operated in parallel.”** Please note that AEP has chosen to vote Negative on TPL-001-5, in part driven by our concerns as provided in our response to Question #6.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that regarding a non redundant single trip coil resulting in a breaker not acting as appropriate, there are other contingency categories that require us to plan for breaker failure such as Category P2 and P4. BPA believes this should not be noted in the footnote and “13d” should be removed.	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI does not agree with the inclusion of Table 1, Foodnote 13 d., the scope of this footnote is too broad.	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
We feel there is still some question as to what this does and does not include. The example of single control circuitry for a trip coil seems to potentially have the same consequence as a category P4 stuck breaker contingency in that the breaker-fail scheme would initiate.	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
The item label in TPL-001-5 is Footnote 13 4, not Footnote 13 d. We agree with having a single control circuity item in Footnote 13. However, we suggest replacing reference to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity. The failure of an auxiliary relay in an interrupting device trip circuit may result in the tripping of more elements than P4 events (fault plus stuck breaker). The simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4 (fault plus stuck breaker) category event.	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
We feel there is still some question as to what this does and does not include. The example of single control circuitry for a trip coil seems to potentially have the same consequence as a category P4 stuck breaker contingency in that the breaker-fail scheme would initiate.	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Yes, however Footnote 13 is numbered and not lettered.	
Likes 0	
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	

With regard to whether or not Footnote 13.d should be included, the answer is Yes, we believe DC control circuitry should be included as a potential single point of failure. However, we believe the language should be expanded to explicitly include auxiliary relays and lockout relays as part of the DC control circuitry for clarity. Furthermore, the DC control circuitry should be further characterized as “tripping DC control circuitry required for Normal Clearing” so that it is clear that single point of failure does not apply to DC closing circuitry or other DC circuitry no required for tripping. In addition, the footnote should limit the tripping DC control circuitry required for Normal Clearing to only that part of the circuitry that would prevent both tripping and initiation of breaker failure. To the extent a single point of failure prevents tripping but does not prevent breaker failure initiation, this contingency would be addressed by a P4 stuck breaker contingency. Finally, should there be a single point of failure in the DC control circuitry that prevents tripping of two circuit breakers but allows for breaker failure initiation on the two circuit breakers, this contingency is worse than a P4 contingency since it represents two stuck breakers, and such an event should be simulated as an independent type of single failure mode under the P5 contingency (while more adverse than a single stuck breaker contingency, it may less adverse than a complete system protection failure which could result in longer clearing delays and additional facilities tripped).

Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.

Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

However, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Yes; however, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS recommends that the specific language previously removed during Draft 1 (Applies to following relay functions or types…) not be deleted, as it is helpful to have the specifics and there is no clear reason or benefit associated with the proposed deletion.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

However, “Circuitry” is a vague term and it is unclear what is intended. Something clearer would be, “Any single control circuit, auxiliary relay, lockout relay, etc., whose failure would delay or prevent tripping” if this is what is truly intended by the standard.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1

Answer	Yes
Document Name	

Comment

Agree.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	Yes
Document Name	

Comment

SNPD does not have additional comments.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment

No Comments

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	Yes
Document Name	

Comment

Yes, because this is a single point of failure.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Note: MISO does not support this comment.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

As stated in its comments regarding the SAR, Texas RE noticed the proposed language for Footnote 13 does not match the NERC Glossary term of Protection System. Texas RE recommends Footnote 13 align with the NERC Glossary to avoid confusion.

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

More clarity on what is in scope would be needed to maintain compliance.

Likes 0	

Dislikes 0	
Response	

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those “with a duration of at least six months” to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) “in consultation with” their Reliability Coordinators (RCs).

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

The PCs and TPs are responsible for complying to the TPL-001-4 standard. RCs are under no obligation to comply with same and have no reason to have input on planning horizon outages (more than 1 year out) that are outside the operations planning horizon (less than 1 year out). No additional entities should be added to the applicability of this standard, including the RC, who is focused on the operations of the system. A gap in communication between PCs/TPs and RCs may put the PCs/TPs in a position where compliance for this standard are not met. In addition:

- The RC has no reason to have detailed information on outages in the planning horizon beyond what is in COS
- Having to respond to every entity within the reliability coordinator area could present an unreasonable burden on the RC and provide risk to the PC/TP if they do not respond
- Reducing the 6 month period to something like “outages spanning the entire season under study” would be reasonable. Limitations that arise due to shorter term outages are an operating horizon issue mitigated by operating practices, not a planning horizon issue.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

MH doesn’t see the value in requiring consultation with RC. MH provides a list of outages to the RC and it doesn’t make sense to ask them to send the list back to us or to ask them to confirm that we should be studying those particular outages.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No

Document Name	
Comment	

The planning assessments are for the Planning Horizon while the RC acts within the Operations Horizon and should not be coordinating the content of planning studies for a disconnected timeframe. Furthermore, this adds a significant burden to the RC and may reduce their focus on more immediate operations.

The language of R1.1.2. also does not provide a clear definition of what types of outages must be considered (e.g. breakers, switches, equipment out for maintenance, etc.).

Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	
Comment	

To require close coordination effort with RCs for outages with a duration of at least six months would be a challenge for base case updates since most planned outages listed on the Coordinated Outage System were tentative plans. Timing and sequential updates would be extremely onerous for PCs and TPs and would be duplicative with operating case development. It would be more practical for SNPD to only review and update base cases to represent system configurations as expected for its annual TPL studies.

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

BPA has the same comments we had during the unofficial comment period. BPA agrees with moving away from the 6-month fixed duration outages.

However, BPA does not agree that consultation with the Reliability Coordinator is necessary. BPA believes the extra coordination would be burdensome and would not provide additional value. BPA already participates in a 45 day regional outage coordination process. BPA believes that this regional coordination process is sufficient to identify the outages to meet Requirement 1, Part 1.1.2. BPA's Planning group studies seasons, anything shorter than 3 months seems more like an operational issue than a planning issue. With a duration of only 3 months, there's a possibility that the outage may not occur simultaneously with the peak for the season. This would not enhance reliability.

Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

The new requirement is open ended and may result in Transmission Planners (TP) performing almost a "real time" operations analysis (i.e. what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (the purpose of TPL-001). NERC IRO-017 Outage Coordination was set up for that purpose, and this proposed change would represent a spillover from IRO-017. The TP would be required to develop a Corrective Action Plan for system outages.

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective.

We recommend the Requirements 1.1.2 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in **BOLD**):

R1.1.2 Known outage(s) of generation or Transmission Facility(ies) as selected **by the Transmission Planner following** consultation with the Reliability Coordinator for the Near-Term **Transmission** Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Alternatively RC should be removed from these Requirements and TP should have the flexibility to select what needs to be studied; as it relates to outages.

In addition, this new requirement would result in Transmission Planners (TP) performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001.

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

This new "consultation" requirement necessitates a correspondence documentation trail that further burdens TP and PC compliance with this already overly complex standard. It is administrative in nature and provides no benefit to the reliability of the BES. We believe that the TP and PC are just as capable to select from the known outages as the RC, and that any consultation with the RC should be at the TP's or PC's discretion.

In addition, while AEP does not object outright to the proposed change that the outages be determined as a result of consultation between the PC/TP and RC, we wonder if such an approach might perhaps lead to inconsistent application and methodologies across the system? The Standards Drafting Team may wish to consider this possibility themselves, and weigh the likelihood of such inconsistencies.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.

Further, clarification needs to be given on the meaning of "consultation" and who has the final responsibility of what outage (if any) needs to included in the study models.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS does not agree with the proposed changes to Requirement 1, Part 1.1.2. AZPS asserts that, giving due consideration to Requirement R4 of IRO-017-1, which came after FERC Order 786, the need to revision Part 1.1.2 has been mooted and is no longer necessary. For this reason, AZPS recommends removal of this requirement.

More specifically, Requirements R3 and R4 of IRO-017 already require coordination between the PC, TP and RC regarding outages in the planning assessment and also requires jointly developed solutions. Thus, the coordination contemplated in Requirement 1, Part 1.1.2 should have already occurred and should not need or be required to re-occur. In fact, AZPS respectfully asserts that the earlier outage and solution coordination occurring as a result of IRO-017 sets up exactly the right process in terms of timing to ensure that outages and solutions are timely, appropriately, and rigorously evaluated. Allowing this coordination to occur in the natural course of operations and not requiring redundant coordination will result in more touch points among the identified entities, facilitating a greater mutual understanding of those outages that would be more impactful to the BES, which understanding better informs the assumptions shaping the inclusion of outages as required by Requirement 1, Part 1.1.2.

For this reason, AZPS respectfully asserts that the coordination and joint solution development requirement included in Requirement 1, Part 1.1.2 be deleted. The inclusion of another coordination and joint solution development beyond that which is required by IRO-017 is not only redundant, but introduces the potential for confusion and ambiguity. Further, the creation of an additional obligation for RC, TP and PC coordination and joint solution development would be simply redundant and would not add enough value to reliability to justify the additional expenditure of resources. Finally, revisiting previous outage coordination and joint solution development would not be cost-effective for any of the involved entities. AZPS recommends removal of the requirement for outage coordination and joint solution development as set forth in Requirement 1, Part 1.1.2.

AZPS further recommends (this is only if deletion is not acceptable) that, since coordination and joint solution development are already occurring under IRO-017, the language of Requirement 1, Part 1.1.2 be revised to state a definitive time period. AZPS respectfully suggests that a 3 month time period for outages is a conservative time period for the inclusion of outages and recommends this time frame as it is generally aligns with those outage time frames that would be considered impactful in the performance of seasonal studies. AZPS recommends the following revisions:

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of three months for the Near -Term Planning Ho for analysis pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

If the language is retained as it is, AZPS respectfully requests that the RC be added as an applicable functional entity to this standard as there is nothing to obligate the Reliability Coordinator to respond within a required period of time, which could affect the Transmission Provider or Planning Coordinator's ability to complete the work in time.

Likes 0	
Dislikes 0	

Response

Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment

The proposed TPL-001-5 standard is applicable only to PC and TP per the Applicability section. But RC is NOT under compliance requirement for this action since the standard is NOT applicable to them. The proposed changes add extra burden on the PC and TP for compliance on which they have no control. Any inaction from RC (non-consultation) can expose PC and TP to possible violation with this part of the requirement.

Moreover, the outage coordination seems to be more of an Operational Planning issue (from the next-day studies up to a year out) than a Transmission Planning issue (beyond year one to year ten studies). No matter how far ahead PC and TP study the system, when it comes to the Operation horizon, the outages need to be studied again with a more realistic system conditions than in the Planning Horizon. Hence any specific analyses performed by PC and TP for the outages in the Planning Horizon don't provide much value to the system operators in the Operation horizon.

Additionally, if the system can't meet the performance requirements due to outages as per R2.1.3 and R2.4.3, the TP and PC have no other allowed mitigation plans, such as operational procedures, except to recommend Corrective Action Plans which result in capital improvement projects. Thus planning for outages in the Near-term Transmission Planning Horizon will only result in capital investment that effect the rates of our customers unnecessarily.

Instead IRO-017 Outage Coordination standard is a much better venue to address FERC's concern from Paragraph 40 of Order No. 786 and TPL-001 standard should be maintained solely as a true Transmission Planning Standard. Besides, this directive pre-dates IRO-017 standard and is not relevant anymore under the proposed TPL-001-5 for outage coordination with durations less than six months. Suggestion: Keep the existing language of R1.1.2 unchanged from TPL-001-4 and address Paragraph 40 directive with revision of IRO-017.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
We believe that any reference to the RC should be removed from this planning standard. Order 786, paragraph 42, clearly states to "include **known** genertor and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." The RC at best has clear visibility of "known" outages for a period of less than one year. The state of the transmission system in the RC environment is based on "real-time" conditions, which are not conducive of conditions reflected in planning models used in assessments for the near-term or the long-term planning horizons. We suggest changing the language of the requirement to "Known outage(s) of generation or Transmission Facility(ies) occuring within the timeframe of the seasonal models or scenarios used in the analyses, pursuant to Requirement 2, parts 2.1.3 and 2.4.3." This allows for the modeling of "known" outages in any model during both peak and off-peak conditions, which include timeframes when maintenance on transmission facilities can take place based on the models which are developed.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We do not agree with the change to Requirement 1, Part 1.1.2. The Planning Coordinator and Transmission Planners have the capability and understanding to select outages that should be included in their Near-term Planning horizon. For those Reliability Coordinators with a significant number of TPs and PCs in their footprint, this requirement change would add a significant burden on the RCs without benefit to the process. The focus of the RC is in the real-time to one year horizon, whereas Transmission Planning should be focused on the one year to five year horizon. If there needs to be an entity to oversee and advise the TPL studies conducted by the TP, it should be the role of the PC. In addition, these studies are already being performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. Even if problems were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an op guide. The	

operational cases have a more accurate near-term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take siginificant new effort and time to complete.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
NVE agrees that outages of less than 6 months should be considered, but does not agree that consultaion with the RC is necessary. A list of outages is provided to the RC by an entity, this consultation would require the entity get that list back and ask them to confirm that we should be studying those particular outages. Further, depending on the number of TP's/PC's, asking the RC to consult with each of them could place an unreasonable burden on the RC and place risk to the PC/TP if they do not respond and also necessitates a documentation trail that would further burden the PC/TP. NVE suggests changing the requirement to outages that span the season under study or other outages as determined by the TP/PC.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA understands that the drafting team has chosen this language in an attempt to provide flexibility to the TPs and PCs conducting their TPL Assesment. WAPA supports the need to change the language due to the concern of missing potential critical outages of equipment because the outage does not fall within the "duration of at least six months". If there are known critical outages that cannot be taken out of service under a significant portion of the year (ex: even under light load levels), a Corrective Action Plan is reasonable. In other words, WAPA supports that a properly planned transmission system should ensure that the known planned removal of facilities for maintenance purposes can occur without the loss of non-consequential load or detrimental impacts to system reliability. The concern is that with the existing proposed language, what information is the RC going to provide for this requirement? Will it be a dump of all non-concurrent outages that are scheduled, which may require the TP/PC conducting the TPL Assessment to spend unneccary efforts in justifying why a specific outage should not be included in a TPL study model? Furthermore, RC's likely will not have knowledge of critical outages that could occur further into the future, but are still within the near term planning horizon (up to 60 months into the future). In reality, for the purposes of TPL studies, it is these critical outages further into the future that are important because when identifying areas where Corrective Action Plans are needed it is important to identify them with sufficient lead time available to implement them.	

A possible suggestion to consider would be to change the language by saying that the System models shall represent known critical planned maintenance outage(s) of generation or Transmission Facility(ies) that are expected to have a detrimental impact to system reliability in the Near-Term Planning Horizon for analysis pursuant to Requirement R2, parts 2.1.3 and 3.4.3. The rationale for those critical outage(s) selected for inclusion shall be available as supporting information.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The concept of known or planned outages needs to have a footnote or further explanation to clarify that this applies to “outages needed to execute the CAP” and be very specific. Maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Our expereince in outage planning has shown that it is very unlikely that “planned” transmission outages exist beyond the next six months and that generator outage schedules are changed frequently. Additionally, to model outages that are expected to last a few weeks to two months into power flow cases that can cover 2-4 months is problematic. The reason is that multiple “potential impactful outages” will likely be identified as canidates to include in the base system power flow model. However, in reality these outages probably don’t overlap thus presenting a complication in selecting what to include in the base system power flow model. Operations Planning builds cases on a daily and weekly basis to assess the impact of planned outages whilch is not practical in the TPL arena. If the Standard stated outages that span the duration of the season being studied that would make this straight forward and remove the RC. While we recognize that the RC is not an applicable entity in this draft of the standard, involving the RC at all in the Requirements is not appropriate either. The responsibility of the RC is “operation” of the system. Any outages in the operating time-frame should have been submitted and reviewed prior to approval. If the RC remains included in the Requirement, need to add words to make it clear that the TP/PC can choose to include the exclusion of stability studies of known outages that might impact steady state but clearly don’t impact stability. Examples might be areas of the transmission system that is not electrically close to generation and not in an area susceptible to FIDVR	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

We agree with the change except that the Requirement should specifically quantify the time period in which the known outage(s) must be scheduled in order to be considered by the RC, PC, and TP. We feel that Requirement 1, Part 1.1.2 should be written as:

Known outage(s) of generation or Transmission Facility(ies) expected to occur beginning after 12-months from the start of an assessment and beginning before the end of the Near-Term Planning Horizon, as selected in consultation with the Reliability Coordinator for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Likes 0	
Dislikes 0	
Response	

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

This requirement places an additional burden on the PC, TP, and RC without any demonstrated benefit to system reliability. Any outage that would be studied as part of the Planning Assessment would be beyond the Operational Planning time horizon. The concept of performing outage planning as part of a Planning Assessment would be difficult to accomplish. In general, maintenance outages are scheduled to minimize the impacts to the system. Depending on the entity's Off-Peak conditions it may be appropriate to include a planned maintenance outage that occurs at regular intervals. However, the RC would not have any insight into how each individual GO and TO schedules maintenance outages. PNM recommends the FERC approach of removing the 6 month threshold from the requirement.

Additionally, the standard as written does not make clear what CAP would be expected if an entity's planned outage results in a system performance violation? Would the standard permit an acceptable CAP to delay the outage or would the standard require transmission improvements are made to address any system performance violations? PNMR recommends the SDT consider making necessary changes to address these ambiguities.

The RC should use IRO-017 to address any concerns they have about planned outage which might mean expanding operations studies to include multiple category events from TPL-001-4.

Likes 0	
Dislikes 0	
Response	

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No

Document Name	

Comment
I support PNM's comments.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment
FMPA agrees with JEA's comments.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment
Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No

Document Name	

Comment
CenterPoint Energy disagrees with the proposed changes to Requirement 1, Part 1.1.2 that the outages represented in System models be selected “in consultation with” Reliability Coordinators (RCs). CenterPoint Energy recommends that Reliability Coordinators (RCs) not be added as an applicable Functional Entity. CenterPoint Energy recommends that TPL-001-5 be applicable only to Planning Coordinators (PCs) and Transmission Planners (TPs). CenterPoint Energy recommends deleting the reference to Reliability Coordinators (RCs) in Part 1.1.2 as follows: “Known outage(s) of generation or Transmission Facility(ies) for the Near Term Planning Horizon irement R2, parts 2.1.3 and 2.4.3.”

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	

Comment
We feel that the proposed language is too subjective and open to interpretation. The idea of “consulting” with the RC to identify known outages adds to the lack of objectivity in identifying known outages and increases the level of complexity in identifying known outages. We believe this concept does not provide clear compliance ownership for the identification of known outages and believe this will make demonstration of compliance by the Transmission Planner unduly complex.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment
The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, and resilient at all times in the future given the lead times associated with making necessary system improvements. Adequacy, reliability, and resiliency include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single

transmission facility has been removed from service for planned maintenance. All transmission facilities require planned outages from time-to-time to facilitate i) maintenance, testing, and/or repair work that cannot be performed hot; ii) to facilitate protection scheme testing, maintenance, and upgrades on facilities with non-redundant protection; iii) to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility; or iv) for other purposes. Therefore, the eventual occurrence of a future planned outage on any transmission facility is certain and "known", not "hypothetical", only the timing and duration of the future outage could be considered uncertain or "hypothetical".   If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy and resiliency to accommodate planned maintenance requirements in general.

In FERC Order 786, the Commission indicated the following at PP 41:

"We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding." (emphasis added)

It is "known" that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the prudent planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient robustness and resiliency to accommodate planned maintenance outages during off-peak periods that will be required regardless of whether or not such activity has been scheduled.

Direction on ensuring the system could meet TPL criteria for future potential planned outages was previously given in an interpretation to TPL-002 and TPL-003. Please consider this, as its intent appears to be lost in forming the TPL-001-4 and TPL-001-5 standards.

http://www.nerc.com/docs/standards/sar/MISO_Interpretation_TPL_Revised_20Mar08.pdf

http://www.nerc.com/files/TPL-002-2b.pdf Pg 11

"The following interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on March 13, 2008:

This provision was not previously interpreted by NERC since its approval by FERC and other regulatory authorities. TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are required. For studies that include planned outages, compliance with the contingency assessment for TPL-002-0 and TPL-003-0 as outlined in Table 1 would include any necessary system adjustments which might be required to accommodate planned outages since a planned outage is not a "contingency" as defined in the *NERC Glossary of Terms Used in Standards."*

While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and resiliency to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate an outage or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedule planned outages when they are needed without sacrificing reliability or load continuity.

A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This scenario would be evaluated only for non-peak conditions. The idea here is that the system does not need to be planned to support planned maintenance during peak load conditions, since those conditions represent a very small percentage of time. However, under periods where planned maintenance is typically performed (e.g., shoulder peak and light load conditions, etc.), the system should be planned to accommodate the planned outage of any one system element (transmission or generation) while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. This additional aspect of the P3 and P6 contingencies will require an adjustment to the traditional contingency definitions to facilitate service to all loads for the planned maintenance outage element in accordance with how the system would be switched for planned maintenance. For example, the planned maintenance outage of a network transmission line section with tapped distribution substations served by the line would be switch-to-switch (only the section between two adjacent distribution substations that required maintenance would be taken out of service) instead of breaker-to-breaker to ensure all load could continue to be served during the planned maintenance outage. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, resilient, and reliable in the future.

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	No
Document Name	

Comment

We disagree with replacing "planned outages of 6 months or more" in Part 1.1.2 with "as selected in consultation with the Reliability Coordinator for the Near -Term Planning Horizon for

The coordination of outages in the Near-Term Planning Horizon between RC, PC and TP is already required by Requirement R4 of IRO-017-1, therefore it should not be duplicated here.

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	

The new requirement is open ended and may result in Transmission Planners (TP) performing almost a “real time” operations analysis (i.e. what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (the purpose of TPL-001). NERC IRO-017 Outage Coordination was set up for that purpose, and this proposed change would represent a spillover from IRO-017. The TP would be required to develop a Corrective Action Plan for system outages.

The new requirement does not address a scenario where the TP does not agree with the RC regarding what needs to be studied, or how such a disagreement would be managed from the compliance perspective.

We recommend the Requirements 1.1.2 be revised as follows to clarify which entity has the sole responsibility to select the outages (additions in RED):

R1.1.2 Known outage(s) of generation or Transmission Facility(ies) as selected by the Transmission Planner following consultation with the Reliability Coordinator for the Near-Term Transmission Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Alternatively RC should be removed from these Requirements and TP should have the flexibility to select what needs to be studied; as it relates to outages.

In addition, this new requirement would result in Transmission Planners (TP) performing an annual study as the RC could request a study to review upcoming outages. This could result in a conflict with the existing Requirements that allow the use of past studies to satisfy compliance with TPL-001.

We agree with the change except that the Requirement should specifically quantify the time period in which the known outage(s) must be scheduled in order to be considered by the RC, PC, and TP. We feel that Requirement 1, Part 1.1.2 should be written as:

Known outage(s) of generation or Transmission Facility(ies) expected to occur beginning after 12-months from the start of an assessment and beginning before the end of the Near-Term Planning Horizon, as selected in consultation with the Reliability Coordinator for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
While the probability of an unplanned contingency during a short duration (less than six month) planned outage is much lower than during a longer planned maintenance outage period, these types of scenarios are already evaluated and planned for in the TPL-001-4 planning assessment through the various N-1-1 contingency combinations. It is PacifiCorp's opinion that the short-term planned outage scenarios are better addressed in the operating horizon. Also see WAPA's comments.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
GTC does not agree with the proposed changes and agree with the comments provided by Xcel Energy, INC. "We believe that any reference to the RC should be removed from this planning standard. Order 786, paragraph 42, clearly states to "include **known** genertor and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." The RC at best has clear visibility of "known" outages for a period of less than one year. The state of the transmission system in the RC environment is based on "real-time" conditions, which are not conducive of conditions reflected in planning models used in assessments for the near-term or the long-term planning horizons. We suggest changing the language of the requirement to "Known outage(s) of generation or Transmission Facility(ies) occuring within the timeframe of the seasonal models or scenarios used in the analyses, pursuant to Requirement 2, parts 2.1.3 and 2.4.3." This allows for the modeling of "known" outages in any model during both peak and off-peak conditions, which include timeframes when maintenance on transmission facilities can take place based on the models which are developed."	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	

Comment

Duke Energy re-affirms its concern with adding short term outages to these planning assessments. As written, this standard requires that a PC must consult with the RC and possibly include in studies short term outages with which the PC has no input on or have any responsibility for outside of this requirement. This is better suited in the Operations Planning horizon based on the operational and dynamic nature of outages with a duration of at least six months.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

1. We believe the SDT is heading in the right direction with the proposed modification. However, the accountability of the RC in the consultation process does not reflect what is already required in NERC Reliability Standard IRO-017-1. As proposed, a PC or TP would need to incorporate any planned outage it became aware of in its Planning Assessment, even if the outage has not yet been processed in an impacted Reliability Coordinator's outage coordination program. Requirement R4 of NERC Reliability Standard IRO-017-1 does require the TP and PC to develop, jointly with their RCs, solutions that resolve issues identified from planned outages included in a Planning Assessment. Moreover, what proof is necessary to demonstrate an applicable entity consulted their RC? Most entities will likely extract approved outage information from a database and not through verbal or electronic communication with their RC. We propose rewording Requirement 1, Part 1.1.2, of the proposed Reliability Standard TPL-001-5 to "outage(s) of generation or Transmission Facility(ies) identified through implementation of its Reliability Coordinator's outage coordination process.
2. We ask the SDT to specify the appropriate RC that should influence an impacted PC's or TP's system model and Planning Assessment. Currently, the proposed language opens the possibility that any RC could provide information regarding a generation or Transmission Facility outage.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We disagree with replacing "planned outages of 6 months or more" in Part 1.1.2 with "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."

The coordination of outages in the Near-Term Planning Horizon between RC, PC and TP is already required by Requirement R4 of IRO-017-1,; therefore it should not be duplicated here.

Likes 0	
Dislikes 0	

Response

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Due to the large number of Planning Coordinators and Transmission Planners in the Reliability Coordinator area, this would be too much of a burden on the RCs to provide appropriate feedback without causing a significant delay or setting the threshhold too low where most if not all planned outages which would significantly increase the time needed to complete the assessment. If the 6 month requirement is removed, the PCs/TPs should provide a reason those planned outages were selected. This would be similar to the language allowing the PCs/TPs to determine which Planning Events are selected to evaluate.	
Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	

The proposed requirement in part 1.1.2 of R1 that TPs and PCs select known outages "in consultation with" their Reliability Coordinators for use in developing planning models creates unnecessary ambiguity. TPs and PCs already have the ability to obtain information about known outages under MOD-032, and TPs and PCs already use that authority in complying with the requirement to include known outages greater than six months long in their planning assessments. So involving the RC in identifying outages for planning models is unnecessary. The "in consultation with" phrasing is also unclear as to the particular efforts required by the TP, PC, and RC. Who bears the burden for the initial communication? What if the RC fails to provide some or all of the outage information? If the RC and TP/PC disagree as to which outages should be included, whose opinion controls? The SRC recommends eliminating this proposed language and instead clarifying the standard to give the TP/PC clear deference in deciding which expected outages should be included in the various planning models. The SRC recommends the following language for part 1.1.2:

1.1.2. Known outage(s) of generation or Transmission Facility(ies) selected by the Transmission Planner or Planning Coordinator in its sole discretion for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

The SRC notes that IRO-017, R4, already requires that "[e]ach Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for

the Near-Term Transmission Planning Horizon." The SRC recommends removing or clarifying this requirement in a future project, since transmission planning requirements should be captured in the TPL standards and because the RC should, as a general rule, have no role in transmission planning activities.

Note: MISO and ISO-NE do not support this comment.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates "operating situations in both next-day analysis and real-time operations." The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO's practice to only take this outage during off-peak conditions due to that very reason. While the use of only "real" known outages is FERC's intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD's planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won't work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC's comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address "a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load." Given that this is FERC's area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	
Comment	

We agree with reducing the duration of known outages from at least 6 months to at least 3 months. However, based on current practices and considering this proposed reduction, it is still doubtful that there would be any planned transmission outages to consider for inclusion in the models for the planning horizon. We do not believe that involving the Reliability Coordinator would lead to any fruitful discussions from a planning perspective.

Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	No
Document Name	
Comment	

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates “operating situations in both next-day analysis and real-time operations.” The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO’s practice to only take this outage during off-peak conditions due to that very reason. While the use of only “real” known outages is FERC’s intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD’s planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won’t work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC’s comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address “a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.” Given that this is FERC’s area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	No
Document Name	

Comment

The RC is not a Functional Entity in the TPL-001-5 Applicability and has no obligation to comply with this standard. The definition of RC states that the RC prevents/mitigates "operating situations in both next-day analysis and real-time operations." The RCs role is in the operations horizon, not the planning horizon. Thus, RCs should not be consulted for outages represented in the planning horizon, which is beyond the scope of their duties. Including this requirement would add additional burden to entities which would now have to coordinate numerous outages with the RC. This additional step will add risk for entities to comply with this standard as it is another form of communication that may not be fulfilled (as in the RC may not respond). The RC would also have the unreasonable burden of coordinating with numerous entities.

Furthermore, this language does not prevent the RC from requesting hypothetical outages. An RC may request that an outage of a critical facility to be studied during peak conditions, when it is the TO's practice to only take this outage during off-peak conditions due to that very reason. While the use of only "real" known outages is FERC's intent, there is no language in the proposed standard to prevent the RC from requesting a hypothetical outage.

In WECC, the Peak RC COS outage management tool used by the RC does not frequently capture outages out into the planning horizon. Additionally, the Peak RC has implemented an outage coordination process to evaluate outages in the operations horizon to manage these risks.

It is important to understand that much like protection system relaying is both a science and an art, one cannot fully study outages without understanding the nature of outage coordination. CHPD's planning engineers work both on planning studies and operational studies, so we are aware that some outages are planned in the future, but when evaluated, simply won't work under those conditions. The proper mitigation, rather than to create a new project to fix this, is to move the outage to a time when it will work or cause more manageable impacts.

Based on FERC's comments under order 786, paragraph 41, the intent of this re-visit on the 6 month criteria is to address "a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load." Given that this is FERC's area of focus, the NERC criteria may consider a criteria in-line with those ends, such as requiring outages that the RC has identified that have required loss of load based on past operational experience. NERC may also consider allowing system adjustments for these outages, as is common with actual operational practice.

Based on FERC's suggestions, a reduced window or definition of a "significant planned outage based, for example, on MW or facility ratings" would be preferred over the outright removal of the 6 month window and the Peak RC additions currently proposed.

Likes 0	
Dislikes 0	

Response

Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance

Answer	No
Document Name	
Comment	

For ease of implementation and efficiency and compliance, a bright line criteria such as “at least six months” is appropriate. There is little reliability risk for outages shorter than this duration and the burden imposed by the coordination requirement is not worth the cost.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	

For ease of implementation and efficiency and compliance, a bright line criteria such as “at least six months” is appropriate. There is little reliability risk for outages shorter than this duration and the burden imposed by the coordination requirement is not worth the cost.

Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1

Answer	Yes
Document Name	
Comment	

Requirement 1, Part 1.1.2 seems to imply that the outages that are selected by the Planning Coordinator (PC)/Transmission Planner (TP) in consultation with their Reliability Coordinators (RCs) should be baked in to the System Models. However, Requirement 2, Part 2.1.3 and Part 2.4.3 indicate that only P1 events should be run on the cases with these outages in place. So, should the outages be removed to perform the studies required under Parts 2.4.1, 2.4.2, and 2.4.4 where we are required to consider P1-P7 and Extreme events? This is a point of the confusion in the current standard as well and we would ask the standard drafting to please clarify.

Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC believes all combinations (N-1-1) should be considered in planning studies for load levels up to those at which the system is typically maintained. It is imperative that the system is planned so that it can be adequately maintained. While ITC agrees with the proposed changes in outages that should be represented in system models to those selected by the PC/TP in consultation with the RC, ITC feels this would be better if included in IRO-017. ITC also agrees with the proposed changes in outages that should be represented in system models to those selected by the PC/TP in consultation with the RC however ITC feels this would be better if included in IRO-017.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
IRO-017 requires the RC to evaluate outages with the PC/TP.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group has a concern that the term ‘Off Peak’ currently could be confusing and recommends that the term should be lower case.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE does not necessarily agree the drafting team met the intent of FERC Order 786, Paragraph 40, which states "…we direct NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude maintenance outages of significant facilities from future planning assessments." The proposed language allows excessive flexibility between the RC and TP/PC, especially considering the RC and PC are frequently the same entity. At the very least, Texas RE recommends a criteria be developed with technical justification for long term outages that need to be modeled as well as criteria to determine which maintenance outages need to be studied. The proposed language could result in not selecting any outages and the entities would still be compliant.

Likes 0	
Dislikes 0	
Response	

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team develop some language that includes the Transmission Owners (TOs) and Generation Owners (GOs) to help close the gap on known outages that are outside of the Operating Horizon to be included in Part 1.1.2. However, if the drafting team feels that developing language to include the TO and GO is not the appropriate action, we would also suggest considering IRO-017 as another option to pursue.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy recommends that the drafting team consider placing the Reliability Coordinator in the Applicability section of the standard**.**	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
No, if consultation with the RC is required in TPL-001-5 then the standard should be applicable to them as well. Also, the reporting requirement R3 in IRO-017-1 should be moved to TPL-001-5.	
Likes 0	

Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

As stated in our comment above, We feel that the proposed language is too subjective and open to interpretation. We believe the proposed language for 1.1.2 does not provide clear compliance ownership for the identification of known outages.

While the draft language places an obligation on the TP/PC to consult, there is no obligation on the RC to respond. What if the RC does not respond or provide timely input? Is the TP/PC held non-compliant for having no planned outages included in the planning assessment?

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy recommends Reliability Coordinators (RCs) not be added as an applicable Functional Entity. CenterPoint Energy recommends that TPL-001-5 be applicable only to Planning Coordinators (PCs) and Transmission Planners (TPs). CenterPoint Energy disagrees with the proposed changes to Requirement 1, Part 1.1.2 that the outages represented in System models be selected “in consultation with” Reliability Coordinators (RCs).

CenterPoint Energy recommends deleting the reference to Reliability Coordinators (RCs) in Part 1.1.2 as follows:

“Known outage(s) of generation or Transmission Facility(ies) for the Near
and 2.4.3.”

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
No, FMPA agrees with JEA's comments for question 7	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
If consultation with the RC is required in TPL-001-5 then the standard should be applicable to the RC. Alternatively, coordination were included in IRO-017 rather than in TPL-001-5 then RC applicability in this standard would not be necessary.	
Likes 0	
Dislikes 0	
Response	
Lynne Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No

Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
The SDT should consider the situation in the TRE Region where ERCOT is both the PC and the RC. Planned outages are not firmly determined until a few months before they are expected to be implemented. ERCOT currently has no input into a TP's annual assessment until such a time that construction requiring an outage is requested. PNMR views this as a potential Operational issue which should be studied at the appropriate time before requesting/taking an outage. Longer lead-time outage timing can be difficult to reliably include in planning studies due to the degree of unknown variables, such project delays, conflicting outage schedules, and as such may not be able to be reasonably included in long-term planning assessments. Further, PNMR recommends including the RC Registration Function in the Standard's applicability given the RC has responsibilities under the standard.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
If suggestions for R1.1.2 provided in question 7 are not accepted by the SDT, then the applicability of TPL-001 should be expanded to include the RC. Without making the RC applicable, then there is no guarantee that the RC will consult with the TP/PC.	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS only agrees with omitting the Reliability Coordinator if R.1.1.2 is deleted as suggested or modified such that it does not require consultation with the Reliability Coordinator as stated above in response to question 7. If the language is retained as is, AZPS respectfully requests that the RC be added as an applicable functional entity to this standard. Unless the standard is applicable to RCs, there is nothing to obligate the Reliability Coordinator to respond within a required period of time, which could affect the Transmission Provider or Planning Coordinator's ability to complete the assessment work in time. AZPS reiterates its comments provided in response to Question 7.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
If the SDT does not accept our comment to clarify and revise R1.1.2, then then the applicability of TPL-001 must be expanded to include the RC, to ensure the RC "consults" with the TP. TO and GO that own Protection Systems should be added to applicability, so that those entities are required to provide the necessary Protection System information to the Transmission Planner so the TP can perform the Planning Analysis.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP agrees with the comments provided by Seattle City Light:	

“If the requirement to consult with the RC remains in the standard, then they should be included in the applicability, but we believe that consultation with the RC is inappropriate for this standard.“	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
If the requirement to consult with the RC remains in the standard, then they should be included in the applicability, but we believe that consultation with the RC is inappropriate for this standard.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
If this requirement remains in the standard, the RC should be added to the Applicability section of the standard. CHPD does not agree with the added requirement to coordinate outages with the RC for the planning assessment.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	

Yes. This is a Planning Standard and the RC does not need to be involved as stated in the response to question 7. However, if the RC involvement remains, they should be included in applicability and should have a time requirement to respond (5 business days) to respond to the Planning Coordinator (PC) or Transmission Planner (TP) if they are in agreement with the maintenance outages to be studied as proposed by the PC/TP.

Likes 0	
Dislikes 0	

Response

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	

Comment
ISO-NE believes that it is most cost-effective and efficient for the RC to be a part of outage determinations. IRO-017 should be modified as required to address this consideration.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	

Comment
Based on our response to Question 7, there is no need for the Reliability Coordinator to be an applicable entity or involved with the TPL-001-5 standard in any way.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment

We believe that consultation between the TP and PC is sufficient for determining known outages to represent in System models.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Please see JEA's response under question #7 above. Address FERC's directive under p.40 from O. 786 with a revision of IRO-017 standard.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA does not agree that consultation with the Reliability Coordinator is necessary.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	Yes
Document Name	
Comment	
SNPD does not have additional comments.	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We do not believe that the RC should be included in the applicability for this standard. As mentioned above, we do not believe that involving the Reliability Coordinator would lead to any fruitful discussions from a planning perspective.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1

Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	
Document Name	

Comment
As noted in the SRC's response to Question 7, above, the language of part 1.1.2, as proposed, is unclear as to the degree to which it requires any action of the RC. If the standard is clarified to give the TP/PC sole discretion in selecting the outages, then the RC has no role in this process, and there is no need to worry about whether the RC should be listed among the entities to whom the standard applies. **Note: ISO-NE does not support this comment.**

Likes 0	
Dislikes 0	

Response

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

No we are not aware of any other standards/requirements that meet these stipulations. However, to reiterate the response and suggestion from Question 7: reducing the 6 month period to something like “outages spanning the entire season under study” would be reasonable. Limitations that arise due to shorter term outages are an operating horizon issue mitigated by operating practices, not a planning horizon issue.

Likes 0	
Dislikes 0	

Response

Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

SNPD is not aware of an existing Standard/Requirement, consistent with industry practice and applicability, that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in system models. This newly suggested Requirement is not practical for PCs and TPs to consider. SNPD obtained initial cases from WECC-approved cases with anticipated topology, system loads and generation. SNPD reviewed and updated these cases based on budget-approved and projected transmission line projects, projected generation resources, and forecasted peak demand data. When a long-term outage (more than 6-12 months) is being planned and needs to be considered for a selected study case, we will update the case to reflect the intended plan for All-Lines-in-Service ("ALIS") N-0 conditions.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP is not aware of any existing obligations that are duplicative of what has been proposed.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
This directive can rightfully be addressed by a revision of IRO-017 Outage Coordination standard. This directive pre-dates IRO-017 and is not relevant anymore to be addressed under the proposed TPL-001-5.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We are not aware of any existing standard/requirement in the planning horizon which requires review and coordination of significant known maintenance outages less than 6 months. However, these outages are typically addressed in the operations timeframe.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	

PNMR is not aware of an existing standard/requirement for the review and coordination of significant known maintenance outages **less than 6 months** in duration.

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	

Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
The TP-002 and TPL-003 had a requirement for planned maintenance flexibility that would have applied to outages less than six (6) months within the planning horizon, but that requirements was not transferred to TPL-001-4 and TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
TEP believes review of planned maintenance outages are more appropriate in the Operating Horizon than the Planning Horizon. This is covered by IRO-017.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a "planned maintenance outage" has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Known facility or equipment outages should be included in the data submittals for the MOD-032 model-building process.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a “planned maintenance outage” has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	No
Document Name	

Comment

No, CHPD is not aware of any other standards/requirements that require review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models.

CHPD currently studies shorter term outages in the Operational Planning Assessment (daily study), the Short Range Study, and seasonal studies as outlined in the Peak RC methodologies. Issues due to short term outages are studied and mitigated in the operations horizon, not the planning horizon. Outages that should be included in the planning horizon should be outages with a duration spanning the entire study window but not any shorter as these are addressed in the operations horizon.

The challenge with this requirement is that this supports the system models used in an entity's system assessment. The more outages to be included in this analysis, the more models an entity must use in order to support this requirement. Multiple model maintenance to support multiple outages can quickly become a potentially burdensome issue.

The idea of a “planned maintenance outage” has currently begun to be addressed under the IRO-017 standard.

Outage planning in the operations horizon can and does identify when outages won't work during a particular season due to system constraints. Outage planning can also help identify when multiple unintentionally overlapping outages would lead to system issues. Requiring these sorts of outage planning activities to also be carried out in the transmission planning assessment will increase burden to entities as there may need to be numerous studies run to identify issues and full outage details are not always firm. It is common practice in operations to mitigate these by re-scheduling the outage. This is a much more cost-effective solution than implementing capital projects to support outages which have not been fully planned out into the Planning Horizon.

Likes 0	
Dislikes 0	

Response

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes

Document Name	
Comment	
For outages shorter than 6 months, there are other assessments (seasonal, monthly, weekly, day ahead and real time) performed by the Transmission Operators or the RC. These outages are included in operating models or EMS models and not the long term planning models.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
NERC IRO-017 Outage Coordination. If SDT wants to include additional requirments that would tighten up the coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models then NERC IRO-017 should be modified. See response to question 7.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
As mentioned above in AZPS's response to Questions 7 and 8, IRO-017-1 R3 and R4, essentially meets the intent of TPL 001-4 Requirement R1 Part R1.1.2. AZPS asserts that, giving due consideration to Requirements R3 and R4 of IRO-017-1, which came after FERC order 786, that Part 1.1.2 is not needed. We would recommend removal of this requirement because R3 and R4 of IRO-017 requires coordination between the PC, TP and RC on outages in the planning assessment and also requires jointly developed solutions. These requirements for coordination and joint solution development associated with outages moots the issue being addressed through the addition of this language. To create an additional obligation for RC, TP and PC coordination would be redundant and would not add value to reliability that would justify the additional expenditure of resources.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Reference IRO-017-1 R3 and R4. Also, our expereince in long-term outage planning has shown that it is very unlikely that “planned” transmission outages exist beyond the next six months and that generation outages are changed weekly.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Outages planned to occur within the next 12-months should be analyzed per the Operations Planning requirements of IRO-017 which is intended to cover the Operations Planning time horizon up to the next 12 months.	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
IRO-017-1	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
NERC IRO-017 Outage Coordination. If SDT wants to include additional requirments that would tighten up the coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models then NERC IRO-017 should be modified. See response to question 7.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
IRO-017 requires review of outages less than 6 months in duration and the purpose of that standard is to ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
IRO-017-1	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Comments: IRO-017 requires the RC to evaluate outages less than 6 months in duration. **Note: MISO does not support this comment.**	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team develop language that will include the Transmission Owners (TOs) and Generation Owners (GOs) to help the modeling process as well as ensuring that those particular entities are included into the applicability section of the standard as well. Also, we recommend the drafting team develop a Requirement that would clearly and definitively explains those entities' responsibilities. However, if the drafting team feels that developing language to include the TO and GO is not the appropriate action, we would also suggest considering IRO-017 as another option to pursue.	
Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment	
In NERC Reliability Standard IRO-017-1, PacifiCorp as a TOP and BA, performs the functions in Peak RC’s Outage Coordination process. IRO-017-1 addresses the 6 month or less outage duration studies, which underscores why TPL-001-5 should continue to address the 6 month or longer duration studies (see Question 7).	
Likes 0	
Dislikes 0	
Response	

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Existing substations that do not meet new requriements should be grandfathered in and allowed to be upgraded when other upgrades/maintenance is being performed. Any new requirements would apply to new substations when they are built.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE does not agree that it would take 36 months to implement TPL-001-5. Since the PC and RC are frequently the same entity, setting up coordination with an RC should not take 36 months.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy cannot agree with a 36 month implementation period. The ambiguity that exist on what constitutes “redundancy” of a protection system component makes it difficult to determine what an appropriate amount of time would be. As written, the standard will require assessments by entities to check components of all protection systems for redundancy, without defining in a clear manner what that redundancy is or should look like. Depending on additional guidance on what redundancy would be, the amount of time that would be needed to do redundancy identification could increase the amount of time necessary to comply with this standard. Without having that clarity, we cannot agree to the proposed 36 month implementation plan.	

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

Since we have significant concerns with the ambiguity of the proposed P5 event / Footnote 13 (see our comments to question #4 and 6), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.

Likes 0	
Dislikes 0	

Response

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees with JEA's comments	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	No
Document Name	
Comment	
No, the 36 month implementation period should be extended for the implementation of any CAP required based on the inclusion of additional planned outages in the Planning Assessment.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	

For utilities having a larger system, a 48 month implementation plan would be preferable to perform a comprehensive field survey of all single points of failure and establish coordination with protection engineers. It also allows additional time to perform the single points of failure analysis required by the standard.

Likes 0	
Dislikes 0	

Response
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment
Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 should be deleted from the standard. Any cascading issue under extreme events is already addressed by Part 4.2 – 4.2.1. Please see JEA's comments on question #1 above.

Likes 1	JEA, 5, Babik John
Dislikes 0	

Response
Long Duong - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment
It will be difficult to agree with the technical assessment to address all Requirements. So the 36 month implementation will be an onerous to nearly an impossible goal that adds little to reliability value.

Likes 0	
Dislikes 0	

Response
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts

Answer	No
Document Name	

Comment

AECI does not agree with the revisions to footnote 13 and cannot support any implementation plan that includes these revisions.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Addressing all Requirements, if any, with the exclusion of sub-requirements 4.2 and 2.7 may require period longer than 36 months.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
36 months may not provide enough time to build new or upgrade the appropriate existing facilities considering permiting, property acquisition, construction, and coordination of outages.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Addressing all new requirements (except 4.2 and 2.7) which would include the new spare equipment strategy for the stability analysis and addressing outages per consultation with the RC, may require a period longer than 36 months. Stability analysis is the most time consuming part of the planning assessment so the additional portion to analyze the spare equipment strategy will take some time to develop. Coordinating outages with the RC will also be very time consuming as there is currently no process in place and the RC will have to correspond with numerous entities regarding numerous outages that have the potential to be in scope.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
There appears to be errors in the text under “Note Regarding Corrective Action Plans.”	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Agree.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

The 36 month implementation plan is reasonable for developing a process with protection engineers to assess single points of failure. The RC process is not necessary.

Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	

Response
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
SCL disagrees with the proposed requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The additional 24 months to implement any resulting Corrective Action Plans for P5 events may be too short. Requirement 4.2 should only be a study requirement and have 36 months to complete. There should be no requirement to implement a Corrective Action Plan for extreme events.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Though SRP disagrees with the proposed language of 4.2., SRP has no concerns specifically with the implementation plan.	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	
Comment	
AECI does not agree with the revisions to footnote 13 and cannot support any implementation plan that includes these revisions.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD disagrees with the proposed Requirements, and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA is concerned that because the system was not designed for extreme events, the fix could be rather intensive requiring a lot of effort and a lengthy lead time to implement. 60 months may not be long enough. BPA believes the focus should be about reducing the likelihood, not preventing it.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	

Answer	No
Document Name	
Comment	

The new language under Requirement R4, Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 should be deleted all together. It goes far beyond what the conclusion from the analysis from Order No. 754 recommended and will cost the industry a very significant amount of time and money for implementation for a comparatively insignificant improvement in the reliability. Requirement R4, Part 4.2 subpart 4.2.1 already addresses the Cascading issue for extreme events in the Commission approved and currently enforceable TPL-001-4 standard and should be left as-is.

We agree that for the Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 events, the system still needs to perform reliably and without any planning criteria violation. However, no operational workaround can be performed for any newly identified violation due to this suggested/clarified language for Footnote 13 and capital improvement projects will be the “only” corrective action plans which will require a significant time and effort for coordination among PCs, TPs and the Facility owners and operators (TO/ TOP/ GO/ GOP). In addition, the installation/ implementation of such Corrective Action Plans may cost the industry tens of billions of dollars with significant construction effort spanning 10-20 years. Hence a mere 60 months (5 years) for meeting Requirement 2, Part 2.7 associated with P5 due to Footnote 13 bullets 2, 3 and 4 implementation and compliance is not adequate and seems too aggressive. The industry needs to be surveyed again to see the outcome from the studies with the modified/clarified language in 5 years (after 36 months for TPL-001-5 effective date + 24 months to develop corrective action plan) to have a more realistic implementation schedule for the remedies (Corrective Action Plans) for Part 2.7.

Suggestion: Part 4.2.2 and both the subparts 4.2.2.1 and 4.2.2.2 under Requirement 4, Part 4.2 is not needed since Requirement R4, Part 4.2 – 4.2.1 already addresses it. Regarding Requirement 2, Part 2.7, an additional industry survey shall be conducted to determine a reasonable and appropriate timeline to implement the Corrective Action Plans just for the newly identified shortcomings for P5 events with the proposed/modified Footnote 13.

Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	
Comment	

A 72 month implementation plan would be preferable 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 would allow additional time for utilities with a larger system and the coordination of outages for implementing Corrective Action Plans.

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No

Document Name	
Comment	
We do not agree with the 60 month implementation plan for projects to address the modified P5 events. These changes will require extensive work in order to make protection systems completely redundant for P5 events, requiring switch houses in some cases. If several switch houses are required, 60 months would not provide adequate time to complete the corrective action plans.	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	
Comment	
FMPA agrees with JEA's comments	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	

Since we have significant concerns with the proposed 4.2.2 language and with the ambiguity of the proposed P5 event / Footnote 13 (see our comments to question #1, #2, #4 and 6), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	

See Duke Energy response to question 10.

Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	No
Document Name	
Comment	

Five years may not be enough time to gather all of the data necessary and fully evaluate all non-redundant components of a Protection.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No

Document Name	
Comment	

Texas RE noticed that Requirement 4, part 4.2 is not called out by name in the implementation plan. The extra 24 months is only mentioned in the General Considerations section and not in the section under Effective Date. It is not clear which requirement the extra 24 months applies to, nor is clear that entities are actually given an extra 24 months as it is not mentioned in the Effective Date section. To clarify these actions need to be done by a certain time, **Texas RE recommends the Effective Date section specify all dates by which all actions need to be completed, organized by requirement number.**

In addition, Texas RE suggests that the monitoring and reporting should be aligned with PRC-005-6 attributes moving forward. If this adjustment is made, the only additional step required by entities would be:

- Identify protective relays without an alternative that provides comparable Normal Clearing times (13.1).
- Identify communication system and dc supply, including monitoring alarming attributes (would already be required for PRC-005-6).
- Identify control circuitry (already required for PRC-005-6).
- Define contingencies for the failure non-redundant components.

There is no reason to believe that these steps could not be accomplished by the effective date of TPL-001-5 and would not need an additional 24 months.

Likes 0	
Dislikes 0	
Response	

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC

Answer	No
Document Name	
Comment	

Existing substations that do not meet new requriements should be grandfathered in and allowed to be upgraded when other upgrades/maintenance is being performed. Any new requirements would apply to new substations when they are built.

Likes 0	
Dislikes 0	
Response	

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Oncor believes the extreme events for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events should not warrant any timetable for developing a Corrective Action Plan. These events are extremely unlikely and would cost Oncor capital project dollars that could have been spent on much more likely events such as single-phase faults with delayed clearing.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	

Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed requirements in Part 4.2 and therefore disagrees with the 60 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The 60 month implementation plan for Req. 4, Part 4.2 and Req. 2 Part 2.7 is appropriate as a significant amount of protection and control related data will have to be gathered in order to facilitate the abilty to perform the new dynamic scenarios.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	
It will take considerable time to develop the contingency events which would need to be included in both steady-state and transient stability studies, whatever is ultimately decided in this regard.	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	
Document Name	
Comment	
No, GTC does not agree with Requirement 4, Part 4.2 (see GTC's response to question #1) and therefore do not agree with the implementation plan.	
Likes 0	
Dislikes 0	

Response

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Involving the Reliability Coordinator will extend the time necessary to evaluate planned maintenance outages which will reduce cost effectiveness. Planned outages are currently evaluated in the Operating Horizon so this results in at least doubling the effort to evaluate planned outages. A bullet listing of the FERC directives would have been beneficial for this question so additional time would not have been required to search the FERC Order to determine all the FERC directives.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Per our response to question 10, depending on what the definition of redundancy actually is, the cost to implement, and become compliant with this standard could be significant. More information as to redundancy is needed.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
No, GTC is concerned that the standard implies CAPs are to be created for extreme events. This would not only be cost ineffective, it would be a heavily burdened standard which would not result in the desired reliability benefits.	

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	No
Document Name	
Comment	
No. See question 7 and 9.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	

Please see comments submitted by Robert Blackne

Likes 0	
Dislikes 0	

Response
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment
SCE agrees that all proposals are the cost-effective approach except one proposal. With respect to SCE's comments for Question 6 regarding Footnote 13d, SCE believes that the intention of the proposed TPL-001-5 to require fully-redundant control circuitry without due consideration of status monitoring combined with periodic independent component testing is duplicative for system reliability and is not the most cost-effective option to address the FERC directive. SCE proposes that the cost-effective solution includes the allowance for excluding control circuitry with montioring from footnote 13 d.

Likes 0	
Dislikes 0	

Response
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment
New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective. New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective. New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies. Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary

Likes 0	

Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA follows JEA's comments, and additionally offers comments below in response to Question 14. We offered these comments in the last comment period and are disappointed that they appear to have been ignored.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The obligation to mitigate the new extreme stability 2e-2h event contingencies, goes significantly beyond the Part 4.2.1 obligations for all other extreme events. WAPA does not believe that the cost/benefit will be reasonable because the frequency of these SPF events are so seldom, they do not warrant the cost to eliminate them. No data has been provided to demonstrate that SPFs have been a significant factor in system outages.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	

We do not believe the proposed changes to footnote 13 as well as the addition of a corrective action plan requirement for extreme events are a cost effective approach. Including the control circuitry associated with the protective functions would cause a large financial burden to retrofit existing stations, or construct new switch houses, for those stations which fail criteria. Requiring mitigations or corrective action plans for extreme events, which have a very low probability of occurring, would also have a large financial impact with very little impact on system reliability.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective. New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective. New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies. Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
Not only some of the proposed recommendations from the SDT are cost-prohibitive, but the added reliability benefit is miniscule as compared to the cost and the aggressive implementation schedule that will be needed to achieve the desired outcome. A more reasonable approach is needed to	

address the directives. The suggestions in the above questions go a long way to achive a very good balance between the cost effectiveness and realiability of the power system.

Likes 1	JEA, 5, Babik John
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

As identified in AZPS's response to question 7 above, there are redundancies associated with outage coordination that reduce the cost effectiveness of the proposed revision. Having this redundant requirement increases the cost without any attendant reliability benefit.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

These changes will take significant engineering resources to study and determine CAPs and potentially significant capital investment to remedy low probability events. It is unlikely that these proposed changes are cost effective.

Likes 0	
Dislikes 0	

Response

Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	

No. See question 7 and 9.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA feels that it is not economically justifiable to spend money on mitigating low probability extreme events. Instead, BPA believes an effort to minimize the likelihood of cascading should be considered if studies indicate there is the potential for cascading on critical parts of the system.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The proposed recommendations to the Standard should meet FERC Directives, however the proposed changes are not cost effective and are somewhat duplicative.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SRP is concerned implementation of corrective actions for extreme events could result in significant costs with little increase in reliability.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
The Cost Effectiveness Background document is the technical rationale. It is doubtful that the proposed changes are cost effective. These changes will take significant engineering resources to study and determine CAPs and potentially significant capital investment to remedy low probability events.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
From a reliability standpoint, the proposed recommendations from the SDT may meet the FERC directives. However, it remains to be seen if the recommendations will be cost effective or a burden to a utility as each has its own set of facilities that are responsible for.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

Review of outages less than six months is not efficient or beneficial.	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Review of outages less than six months is not efficient or beneficial.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

The new spare equipment strategy for stability analysis against P1 and P2 contingencies does not represent a cost effective implementation either. FERC's language in order 786 paragraph 89 states "However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4". In CHPD's experience, the impacts that the steady state analysis was trying to evaluate were thermal and voltage violation in nature; thus to analyze the loss of equipment that provided this function on the system, such as large power transformers, made sense. However, stability simulations, in our experience, are more strongly impacted by clearing times. Therefore, the spare equipment analysis that is useful for the steady state analysis does not typically modify these clearing times, and thus will not likely yield meaningful results to the degree that it does for the steady state analysis. NERC may consider additional language or guidance regarding the stability application of the new spare equipment strategy to better focus its application to those contingencies where clearing times and as a result, stability could be impacted by the loss of the spare equipment.

Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	

Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	No
Document Name	
Comment	

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

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Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No
Document Name	
Comment	

New Part 2.4.3 – This obligation to study P1 events for known outage conditions is expected to be cost effective.

New Part 4.2.1 – This obligation is a relocation of the existing second obligation in Part 4.5 of the TPL-001-4 standard and expected to still be cost effective.

New Part 4.2.2 – The obligation to evaluate the new extreme stability 2e-2h event contingencies, go significantly beyond the Part 4.2.1 obligations for all other extreme events and are not expected to be cost effective. The 2e-2h contingencies are classified as extreme events, but Part 4.2.2 requires actions beyond the Part 4.2.1 obligations for the other extreme events, namely the development of a list of possible actions to prevent Cascading, a timetable for implementation of the possible actions, and annual continued review of the implement status and validity of the possible actions. No justification has been provided to justify the expenditure of significantly more time and resources for the new 2e-2h contingencies.

Footnote 13 4 – The obligation to evaluate single control circuit failures is expected to be cost effective, if our recommendation to replace reference to trip coils is replaced with a reference to control circuit auxiliary relays is implemented. Otherwise, the simulation of trip coil failures is not expected to be cost effective because it will be duplicative of a P4 category event simulation, and therefore, unnecessary.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

In particular, the proposed recommendation of the standard drafting team regarding the removal of the 6 month window does not represent a cost effective approach due to the lack of a timeframe. This could open the door to numerous un-coordinated outages whose impacts could be better mitigated through outage coordination in the operational timeframe under the existing IRO-017 requirements.

The new spare equipment strategy for stability analysis against P1 and P2 contingencies does not represent a cost effective implementation either. FERC's language in order 786 paragraph 89 states "However, the Commission will not direct a change and instead directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4". In CHPD's experience, the impacts that the steady state analysis was trying to evaluate were thermal and voltage violation in nature; thus to analyze the loss of equipment that provided this function on the system, such as large power transformers, made sense. However, stability simulations, in our experience, are more strongly impacted by clearing times. Therefore, the spare equipment analysis that is useful for the steady state analysis does not typically modify these clearing times, and thus will not likely yield meaningful results to the degree that it does for the steady state analysis. NERC may consider additional language or guidance regarding the stability application of the new spare equipment strategy to better focus its application to those contingencies where clearing times and as a result, stability could be impacted by the loss of the spare equipment.

Lastly, the proposed changes will add burden to entities and could result in great costs for potentially documenting and implementing mitigation for cascading due to Extreme Events.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	Yes
Document Name	

Comment

As are the proposed modifications outlined in our comments.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

FERC has directed that the effects of non-redundant components of a system protection system be evaluated. While not all issues of non-redundant parts of a non-redundant propective system are evaluated, the significant items are to be studied. If cascading occurs, a project should be identified.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	Yes
Document Name	

Comment

Note: MISO does not support this comment.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	
Document Name	
Comment	
No comment.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	
Document Name	
Comment	

No comment.

Likes 0	
Dislikes 0	

Response
Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5

Answer	
Document Name	

Comment
Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	

Response
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF

Answer	
Document Name	

Comment
No comment.

Likes 0	
Dislikes 0	

Response

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We wish to change this to YES. This TPL-001-5 update should coordinate with the proposed changes to FAC-010, FAC-014 and the new FAC-015 standards. Specifically, the requirements in FAC-015 specify what system operating limits should be used in planning assessments. Standard TPL-001 covers all other requirements relating to planning assessments. Having a separate standard defining the limits that should be used in planning studies adds unnecessary complication and potential for confusion, therefore these new FAC-015 requirements should be included within TPL-001-5. The fact that both of these standards are being updated now should be taken advantage of so that there are no reliability gaps.	
Likes 0	
Dislikes 0	
Response	
Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD does not have a comment.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	No
Document Name	
Comment	
Not aware of any.	
Likes 0	
Dislikes 0	

Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Giles - Westar Energy - 1

Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Payam Farahbakhsh - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lauren Price - American Transmission Company, LLC - 1 - MRO,RF	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
The proposed TPL-001-5 requires implementation of capital projects, which directly conflicts with our provincial regulations. We cannot legally adopt this standard. MH will have to review the final changes in detail to determine what to implement as a MH standard.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The language of 4.2.2. can be construed as requiring implementation of of corrective actions which include capital projects and additional infrastructure. Such a requirement would contradict the Energy Poicy Act of 2005, specifically the section below: **Energy Policy Act of 2005** **TITLE XII—ELECTRICITY** **Subtitle A—Reliability Standards** **SEC. 1211. ELECTRIC RELIABILITY STANDARDS** **SEC. 215. ELECTRIC RELIABILITY** ''(2) This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes

Document Name	
Comment	
Due to the changes incorporated in this proposed TPL standard, Reliability Standard CIP-014-2 – Physical Security can be impacted with the outcome. The proposed TPL-001-5 is setting the bar higher than before for the PC and TP. This can result in a different scenario for applicable Transmission Facilities for CIP-014-2 as identified by PC and TP (CIP-014-2 – section 4. Applicability – 4.1. Functional Entities – 4.1.1 – 4.1.1.3) in accordance with the proposed TPL-001-5 analyses.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	
Comment	
IRO-017 already defines the process for studying outages within the Operational Planning Horizon. This standard sets a difference process for the Planning Horizon creating disconnect between operations and planning.	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
FMPA agree's with JEA's comments	
Likes 0	
Dislikes 0	
Response	

Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Assuming that the maintenance outages should be evaluated in the Operating Horizon as discussed in question #9, this could have conflict with IRO-017.	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	
Response	
Joyce Gundry - Public Utility District No. 1 of Chelan County - 3	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in industry.	
Likes 0	
Dislikes 0	

Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
As mentioned previously, CHPD is aware of redundancy definitions in the 2009 NERC document “Protection System Reliability – Redundancy of Protection,” as well as some of the redundancy methods and requirements described in PRC-012-2 (for RAS systems), which is subject to future enforcement. These multiple NERC definitions of acceptable types of redundancy will likely cause confusion in the industry.	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No	
Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	
Please see comments of Joe O'Brien NIPSCO.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

14. Do you have any other general recommendations/considerations for the drafting team?

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
See MidAmerican Energy's comments.	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
Please see comments submitted by Robert Blackne	
Likes 0	
Dislikes 0	
Response	
Hien Ho - Tacoma Public Utilities (Tacoma, WA) - 4	
Answer	No
Document Name	
Comment	
If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6.	
Likes 0	
Dislikes 0	
Response	

Long Duong - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
SNPD does not have additional comments.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We wish to change this to YES. *R1.1.2. 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..* SCL comments: The requirement does not clarify who selects the outages to be included in the study. Will it be at TP's discretion, or will all the outages proposed by the RC be included in the study(ies)? Also, the language did not specify the duration of the outage as selected in consultation with the RC. SCL's previous recommendation calls for outage that fall within the entire season of the planning horizon under study.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gary Trent - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Greg Davis	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Giles - Westar Energy - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 1, Group Name AECI & Member G&Ts	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We agree that Footnote 13 is an improvement over the previous. However there are still some ambiguities that should be clarified either directly or through appropriate descriptions in the rationale boxes or supplementary material section. We believe ambiguities may lead to confusion during the necessary Protection System assessments, or unnecessary expenditures by entities. 13.b Please clarify wording on “a single communication system (…) which is not monitored or reported”. Please clarify if the intent is that a “single monitored communication system” means that a single communication channel which is monitored and reported meets the redundancy requirement. 13.c - Please clarify the term “open circuit” and provide an example (in the supplementary material). An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. Is it the intent of this footnote to capture only the opening of the main protective device (breaker/fuse) after the DC system? If so, the following wording is offered as suggestion: “13.c A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, either directly or indirectly, for both low voltage and for interruption of the total station DC supply by any immediate downstream protective device.” We believe this wording along with appropriate rationale and an example would help clarify this footnote.	
Likes 0	
Dislikes 0	

Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
MOD-032 should be considered for modification to specifically require protection data, including non-redundant elements, if this standard is approved.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
1. We ask the SDT to identify VSLs for Requirement R8. 2. The Standards Authorization Request associated with this project provides the SDT an opportunity to evaluate requirement retirements under Paragraph 81 criteria. We believe Requirements R5, R6, R7, and R8 fall under such criteria. Documenting acceptable voltage limit deviations are all necessary, yet are likely documented as assumptions and technical rationales listed within Planning Assessments. Moreover, these criteria are not directly associated with the required execution of conducting studies. The identification of study coordination roles and responsibilities through meeting minutes and distribution of Planning Assessment results to appropriate entities within a specific time period are administrative activities. Further proof is that these requirements do not have performance-based VSLs identified. We ask the SDT to review these standards and identify reasons why Paragraph 81 criteria do not apply. 3. We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy suggests that objectives outlined in the FERC Directives could be accomplished without the need to revise the standard in this manner. The objectives could be met in the form of a NERC project or initiative requesting that these assessements/studies be done in 10% or 20% intervals over a set period of time, and the data submitted to NERC for its review. We feel that requiring these objectives in a standard, with the ever changing	

configuration of the system, would require that this work as proposed be done every year, which would be extremely burdensome. We recommend that the studies and assessments that will be required would be better suited outside of the NERC standards.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

TPL-001-5 R8 should include distribution to impacted RCs and IRO-017-1 R3 be removed.

Traditionally the intent of "extreme events" or "extreme contingencies" was to create awareness of the impacts of the studied contingencies, but not establish design requiements. Therefore we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes:

Category: P8 Multiple Contingency

Initial Condition: Normal System

Event: 2e through 2h

Fault Type: 3 phase

BES Level: HV, EHV

Interruption of Firm Transmission Service Allowed: Yes

Non-Consequential Load Loss Allowed: Yes

With this change, Requirement R4.6 should be revised as follows: " If the analysis concludes there is Cascading caused by the occurrence of Table 1 planning events P8, a Corrective Action Plan shall be developed….."

The definition of "Near-Term Transmission Planning Horizon" needs to be clearly documented in the NERC Glossary of Terms. The current definition of "The transmission planning period that covers Year One through five" is not without ambiguity as the meaning of 'covering Year One' is not universally agreed upon.

The definition of "Year One" in the NERC Glossary of Terms is defined as

The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

If a Transmission Planner begins an assessment in January of 2011, Year One would include the peak load for 2012 (August) which is 19-months in the future or for 2013 which is 31-months in the future. If a Transmission Planner begins an assessment in December of 2011, Year One would include the peak load for 2012 (August) which is 8-months in the future or for 2013 which is 20-months in the future.

'Year One' covering a time period of as short as 8-months or as long as 31-months is not clear and will lead to misunderstandings and different interpretations of NERC Requirements. We propose that 'Year One' should be defined as:

The time period of the first twelve months beginning on the date an assessment is started.

The definition of "Near-Term Transmission Planning Horizon" would then be completely clarified if it was defined as:

The transmission planning period that begins with the end of Year One and continues through the next four forecasted peak Load periods.

The definition of "Long-Term Transmission Planning Horizon" would also be completely clarified if I   t was defined as:

The transmission planning period that begins with the fifth forecasted peak Load period and continues through the tenth forecasted peak Load period (or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete).

Additionally, all of the time periods (such as "Long-term Planning", "Operations Planning", "Same-day Operations", "Real-time Operations", and "Operations Assessment") described and defined in the NERC document "Time Horizons" (most recently modified in 2014) should be moved into the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Payam Farahbakhsh - Hydro One Networks, Inc. - 1

Answer	Yes
Document Name	

Comment

We agree that footnote 13 is an improvement over the previous. However there are still some ambiguities that should be clarified either directly or through appropriate descriptions in the rationale boxes or supplementary material section. We believe ambiguities may lead to confusion during the necessary Protection System assessments, or unnecessary expenditures by entities.

13.b

Please clarify wording on “a single communication system (…) which is not monitored or reported”. Please clarify if the intent is that a “single monitored communication system” means that a single communication channel which is monitored and reported meets the redundancy requirement.

13.c

Please clarify the term “open circuit” and provide an example (in the supplementary material).

An open circuit in the battery system can be caused by many things, such as loose connections at the battery or any downstream DC breaker/fuse opening. Is it the intent of this footnote to capture only the opening of the main protective device (breaker/fuse) after the DC system?

If so, the following wording is offered as suggestion:

> **“13.c A single DC supply associated with protection functions, and that single station DC supply is not monitored or not reported, either directly or indirectly, for both low voltage and for interruption of the total station DC supply by any immediate downstream protective device.” We believe this wording along with appropriate rationale and an example would help clarify this footnote.**

Likes 1	Hydro One Networks, Inc., 3, Malozewski Paul
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	Yes
Document Name	

Comment

There is no mention of instrument transformer failure as a single component failure, but such failures could directly result in a failure to trip and thus subsequent reliance on delayed remote backup protection to clear the fault. A NERC technical paper titled “Protection System Reliability – Redundancy of Protection System Elements”, which was prepared by the NERC System Protection and Control Subcommittee and dated November 18, 2008, correctly indicates that instrument transformers can represent a single point of failure in a protection system as follows:

From Section 5.1 of the technical paper: “At least two isolated and separate AC current sources (referred to as CT inputs) for Protection Systems are required to meet the proposed requirement for CT redundancy. Figure 5-3 shows a common arrangement that addresses the current measurement redundancy requirement. CTs are required to provide totally separate secondary AC current sources for each redundant Protection System. This is required so that a shorted, open, or otherwise failed CT circuit will not remove all protection elements requiring current.”

From Section 5.2 of the technical paper: “At least two separate secondary

windings supplying voltages for Protection Systems are required to meet the proposed requirement for AC voltage source redundancy when such voltage sources are required to satisfy the BES performance required in the TPL standards. This is required so that a shorted, open, or otherwise failed voltage circuit will not remove all protection elements requiring voltage.”

The proposed requirements outlined in the NERC technical paper align well with how most transmission owners have historically developed fully redundant protection schemes, and thus should be incorporated into Footnote 13 of the proposed TPL-001-5 standard.

Unless the SDT has statistical data that supports the notion that the probability of an instrument transformer failure is much lower than the probability of other failure modes identified in Footnote 13, Footnote 13 should be expanded to include instrument transformers, or at a very minimum, current transformers and voltage transformers with single secondary windings.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	Yes
Document Name	

Comment

Additional Comment for consideration, related to clarification of the Standard:

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1…..” Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

Footnote 13 should be modified so that the subsections of the footnote are alphabetical (i.e., a, b, c, and d) and not numerical. Currently, the subsections are numbered, one through four.

SCE provided recommended modifications of footnote 13, subsection d, in response to Question 3 for the comment period ending May 24, 2017. SCE would like to reiterate our feedback from the prior comment period. Please see comments submitted by Deborah Vandeventer.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

We proposed the following general recommendations.

1. Footnote 13 – For the introductory sentence, we suggest; “If the following components of a Protection System are not redundant, then failure of one component must be evaluated”.

2. Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; “Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken

Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	2015-10_TPL-001-5_Unofficial_Comment_Form_FMPA (003).pdf
Comment	
FMPA cannot support the standard revision with the addition of 2.4.3 as it is currently worded. FMPA pointed out in the previous comment period that the language used effectively eliminates the ability to apply engineering judgement to study those events that are expected to produce more significant impacts in the Stability analysis portion of the Planning Assessment. As currently worded, 2.4.3 would required Stability analysis of all P1 events which would result in a tremendous amount of work, but very little benifical insight, since P1 events are typically much less severe from a stability perspective. While comments indicating that proposed methods are "too much work" are not often taken very seriously, due to the fact that R2.4 is in reference to the Stability analysis, the amount of additional work, especially for some larger Planning Coordinators and Transmission Planners, could be completely infeasible to simulate and to thoroughly review results (log files and plots). FMPA believes the intent of the drafting team was to capture stability issues related to "known outages", but has unintentionally gone well beyond that. FMPA supports the drafting team exploring whether IRO-017 is the appropriate standard to address FERC's concerns regarding planned outages, but at a minimum believes 2.4.3 needs to be reworded. FMPA suggests an approach very similar to the language used in 2.4.5 to address this issue (i.e. – "selected P1 events….expected to produce more servere System impacts…").	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	Yes
Document Name	
Comment	
I support PNM's comments.	
Likes 0	
Dislikes 0	
Response	
Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1	
Answer	Yes
Document Name	

Comment	
PNMR recommends that R8 should be revised to include the impacted Reliability Coordinators. With this revision, PNMR believes that IRO-017-1 R3 could be retired as this standard would accomplish the intended reliability objective and would reduce the administrative burden on PCs and TPs. PNMR further recommends that R4 from IRO-017-1 be added to TPL-001-5 R2.7 since it is requiring the CAP be developed with the RC. In addition, the SDT should consider adding the RC as an applicable entity. With this revision, IRO-017-1 R4 could be retired as this standard would accomplish the intended reliability objective. The intention of R2.4.3, as written, is unclear. Is the intention to require known outages be included in the assessment of System peak and Off-Peak conditions? The requirement should be revised to clearly define what is required to be in compliance.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

The definition of “Near-Term Transmission Planning Horizon” needs to be clearly documented in the NERC Glossary of Terms. The current definition of “The transmission planning period that covers Year One through five” is not without ambiguity as the meaning of ‘covering Year One’ is not universally agreed upon.

The definition of “Year One” in the NERC Glossary of Terms is defined as

The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

If a Transmission Planner begins an assessment in January of 2011, Year One would include the peak load for 2012 (August) which is 19-months in the future or for 2013 which is 31-months in the future. If a Transmission Planner begins an assessment in December of 2011, Year One would include the peak load for 2012 (August) which is 8-months in the future or for 2013 which is 20-months in the future.

‘Year One’ covering a time period of as short as 8-months or as long as 31-months is not clear and will lead to misunderstandings and different interpretations of NERC Requirements. We propose that ‘Year One’ should be defined as:

The time period of the first twelve months beginning on the date an assessment is started.

The definition of “Near-Term Transmission Planning Horizon” would then be completely clarified if it was defined as:

The transmission planning period that begins with the end of Year One and continues through the next four forecasted peak Load periods.

The definition of “Long-Term Transmission Planning Horizon” would also be completely clarified if it was defined as:

The transmission planning period that begins with the fifth forecasted peak Load period and continues through the tenth forecasted peak Load period (or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete).

Additionally, all of the time periods (such as “Long-term Planning”, “Operations Planning”, “Same-day Operations”, “Real-time Operations”, and “Operations Assessment”) described and defined in the NERC document “Time Horizons” (most recently modified in 2014) should be moved into the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The current draft of the standard seems to straddle the fence between Planning Events and Extreme Events for the performance requirements of Items 2e – 2h. Thus, we suggest that 2e – 2h be placed in one or the other. Our recommendation is to not require a CAP.

If the intent is to not require a CAP, it should be inserted into the Extreme Events category but with the same performance requirements as all the other Extreme Events (i.e., assessment of determining strategies to manage cascading which don’t have to be implemented should not be required).

If the intent is to require a CAP, which we do not recommend, other alternatives include:

The requirements in the Extreme Events Table 2e-h should be depicted in Table 1 Planning Events as a second Row of P5 with three-phase as the “fault-type” for several reasons:

1.
    i. Table 1 note (a) already covers “cascading” not being allowed – maybe eliminating the need for a new R4.6 altogether
    ii. Clearly shows this as a signitifcant “raising-the-bar” event requiring a CAP
    iii. Maintains the separation between Planning Events (requiring a CAP) and Extreme Events (requiring analysis and optional CAP)

An alternative to it being depicted as a second row of P5 with three-phase as the “fault type” could be to make a P8 for stability only.

R2.4.5: Need some verbiage to allow for excluding studies of unavailable equipment that might impact steady state but clearly don't impact stability. Examples might be areas of the transmission system that are not electrically close to generation and not in an area susceptible to FIDVR. An extra sentence "Analysis, including simulations as detailed in R2.4.5, are required only for scenarios where a stability impact could be possible as a result the unavailable equipment" or something similiar would be appropriate. If clarifying verbiage is not included, the result would be the need to devote countless manhours to perform studies that will provide no reliability value.

Suggest changing "Table 1 – Steady State & Stability Performance Extreme Events" to "Table 2 – Steady State & Stability Performance Extreme Events" as these are two separate tables.

The rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onerous (Extreme Events Table – stability 2e – 2h). This scenario with a SLG fault is onerous enough

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

We proposed the following general recommendations.

Footnote 13 – For the introductory sentence, we suggest; "If the following components of a Protection System are not redundant, then failure of one component must be evaluated".

Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; "Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5

Answer	Yes
Document Name	
Comment	

In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…"

Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	Yes
Document Name	
Comment	

NVE has some additional comments regarding stability analysis for an entities spare equipment strategy. NVE would like to see some additional language regarding the selection of selected P1 and P2 category events. Perhaps language similar to what is in R4.4 would help to add some clarifying language as to which P1 and P2 contingencies shoud be studied for the spare equipment analysis.

Extreme events 2e – 2h involves studying 3 phase faults on various elements with a failure of a non-redundant component of a protection system. In the presence of a protection system single point of failure, this fault type may not be the most critical. Since most modern protection systems are designed using a higher lever of redundancy, the extreme events described in 2e – 2h will be most applicable to legacy protection systems. Many of these legacy protection systems use single phase electromechanical or solid state relays. With a three phase fault, failure of a single relay would not impact the ability to detect and clear a fault since the relays on the other phases would detect and intitiate clearing as though no relay failure had occurred. For a line to ground fault with a failed relay on that phase, the fault would need to detected and cleared through other means and result in delayed clearing. For a line to ground fault that develops into a three phase fault and mentioned in the technical rationale document, as soon as the fault developed into a three phase fault, the other relays would detect the fault and then clear as appropriate. A line to ground fault would either have to wait to develop into a three phase fault to be cleared or wait until remote relays detect and clear the fault. It would then appear that the line to ground fault with a failed relay would have a greater impact than a three phase fault with a failed relay. NVE recommends that the extreme event 2e – 2h be modified to line to ground faults or something along the lines of “if the non-redundant protection systems is implemented using single phase or ground relays, the 2e – 2h element faults must also be studied for single line to ground faults with delayed clearing.

Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1,3,4,5

Answer	Yes

Document Name	
Comment	
In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…”	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
We believe the drafting team should revisit the economic impacts of the proposed changes, specifically those concerning extreme events.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
We proposed the following general recommendations. {C}1. {C}Footnote 13 – For the introductory sentence, we suggest; “If the following components of a Protection System are not redundant, then failure of one component must be evaluated”. Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. After the list of the four types of applicable comments, we suggest adding; “Current instrument transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not to be considered as applicable Protection System components for P5 category events.	
Likes 0	
Dislikes 0	

Response	
Joe McClung - JEA - 1,3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
We again appreciate all the hardwork and expertise of SDT for this project. The data request and analysis after Order No. 754 was a good first step towards addressing the single points of failure in the protection system and the proposed language in TPL-001-5 is an improvement upon that criteria. The SDT is headed in the right direction and with some additional guidance/suggestion from the industry; as received during the prior informal comment opportunity and this formal comment period; the directives from FERC and concerns from the SPCS and the SAMS can be easily achieved with minimal burden to the rate payers/customers of the electric power industry but with significant improvement in the reliability of Bulk Power System.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Item 4 of the footnote 13 should be rewritten to clarify what is meant by a single control circuit. As written, it is unclear whether it requires two completely independent circuits or simply two independent elements in one circuit.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
In Footnote 13.3 of Table 1, it would be clearer to state, “A single station dc supply associated…”	
Likes 0	

Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP is concerned that this project and the proposed revisions go beyond the SAR in a number of ways. Of greatest concern is the inclusion of Footnote 13b (communication systems) and the inference of a Corrective Action Plan in R 4.2.2 (originally provided as R 4.6 in draft 1 from the informal comment period). Because the SAR's scope and direction did not include these topics, we believe these proposed revisions should be removed.	
Likes 0	
Dislikes 0	
Response	
Daniel Grinkevich - Con Ed - Consolidated Edison Co. of New York - 1	
Answer	Yes
Document Name	
Comment	
Traditionally the intent of "extreme events" or "extreme contingencies" was to create awareness of the impacts of the studied contingencies, but not establish design requiements. Therefore we recommend moving Table 1 Extreme Events Stability elements 2e through 2h from the Extreme Events table to Table 1 Planning Events, under a new Category P8, with the following attributes: Category: P8 Multiple Contingency Initial Condition: Normal System Event: 2e through 2h Fault Type: 3 phase BES Level: HV, EHV Interruption of Firm Transmission Service Allowed: Yes Non-Consequential Load Loss Allowed: Yes With this change, Requirement R4.6 should be revised as follows: " If the analysis concludes there is Cascading caused by the occurrence of **Table 1 planning events P8**, a Corrective Action Plan shall be developed….."	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
After reviewing R1.1.2, BPA believes that the term “Transmission” needs to be inserted into the term “Near-Term Transmission Planning Horizon” to be consistent with the defined term in the NERC glossary.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
• Perhaps this is an opportunity to link TPL-001-5 and PRC-023-4 into a single assessment? • The timing of models developed under MOD-032 sometime make it difficult to have an exact “year five” model. R2.1.1 could be more flexible – similar to 2.1.2.	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Requirement R1, Part 1.1.2 in TPL-001-5 has language that is redundant to IRO-017-1, Requirements R3 and R4. • Both address planned outages in the Near-Term Planning Horizon.	

- Both require the Transmission Planner and Planning Coordinator to consult with the Reliability Coordinator regarding the selection of know generation and Transmission outages for the Near-Term Planning Horizon.

LSPT prefers the team's language changes in TPL-004-5 for planned outage modeling as opposed to the current IRO-017-1 requirements.

Redundant requirements in NERC Reliability Standards are unwarranted. In FERC's order (issued March 15, 2012 in RC11-6-000) in response to NERC's "Find, Fix, Track, and Report" proposal stated, in part, the following in Paragraph 81:

"…. some current requirements likely provide little protection for Bulk-Power System reliability or may be redundant. The Commission is interested in obtaining views on whether such requirements could be removed from the Reliability Standards with little effect on reliability and an increase in efficiency of the ERO compliance program. If NERC believes that specific Reliability Standards or specific requirements within certain Standards should be revised or removed, we invite NERC to make specific proposals to the Commission identifying the Standards or requirements and setting forth in detail the technical basis for its belief."

In response to Paragraph 81, NERC filed (and FERC subsequently approved) the retirement of 34 requirements within 19 Reliability Standards – see Order No. 788, RM13-8-000. These changes were approved with a single Standard Authorization Request ("SAR")

LSPT understands that Project 2010-10's SAR limits the drafting team's scope to changes to TPL-001-4. Therefore, LSPT recommends that the drafting team propose a revision to the SAR that would allow the team the flexibility to address any NERC approved standard with requirements that addresses planned maintenance outage modeling in planning assessments when the team addresses Paragraph 40 in Order 786. (Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six-month threshold could exclude planned maintenance outages of significant facilities from future planning assessments.)

This proposed SAR change is an example only. However, a SAR change is needed to allow the team the flexibility to propose the retirement of IRO-017-1 Requirements R3 and R4 concurrent with the approval of TPL-001-5 Requirement R1, Part 1.1.2.

Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group feels that an alternative first step should have been in a PRC Standard to address the concerns in reference to Single Point Failure. Furthermore, there could be a potential disconnect between the Transmission Planner and Protection Engineers by placing this only in a Planning Standard. Also, we recommend that the draft team includes the Transmission Owner (TO) and Generator Owner (GO) in the applicability section, along with an additional requirement specifying that the TO and GO should provide pertinent data (e.g., contingency definitions, elements tripped) upon request by the PC in order to assess the impact of Single Point of Failure in their assessments.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a “more severe System impact” standard of performance. This begs the question, “More severe than what?”	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1,5, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a “more severe System impact” standard of performance. This begs the question, “More severe than what?”	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the efforts of the SDT in revising TPL-001-5 – Transmission System Planning Performance Requirements. BC Hydro votes “No” and wishes to provide the following two comments 1. At present BC Hydro is not aware of the process and criteria of Reliability Co-ordinator in identifying planned outages for the Near Horizon assessment pursuant to Requirement R2, parts 2.1.3 and 2.4.3. Accordingly, BC Hydro is not in a position to assess the impact of this modification to the standard.	

2. The proposed amendments scope from Single Point of Failure is very wide, which will apply to the entire bulk electric system i.e. 100 kV and above. Our recommendation would have been affirmative if the scope were limited to extra high voltage (360 kV and above), where a single point of protection failure after a fault can trigger a major system disturbance.

Below extra high voltage levels, BC Hydro protection systems are built using principles of good utility protection practices, as described in the ANSI/IEEE standards and guides, to ensure that they have acceptable reliability i.e. clear faults without mis-operating. Our protection systems are largely redundant but still can have a single point of failure, such as where there is a shared breaker trip coil or a single telecom fibre etc. Based on our fifty years of operating experience, there is no known case where a single point of failure in our high voltage protection system precipitated in a major system disturbance event. It is because probability of a single failure (in our redundant high voltage protection system) impacting our system performance is negligible. Yet demonstrating compliance to the proposed amendments will require BC Hydro to redirect our critical resources (financial and people) in identifying single points of failure in our every single high voltage P&C asset, estimate incremental protection clearing time associated that failure, and then demonstrate acceptable system performance during the event. Instead of redirecting our critical resources to demonstrate compliance to this negligible probability event, BC Hydro will receive higher reliability benefits by continuing to invest our resources in upgrading the aging protection systems.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 6

Answer	Yes
Document Name	

Comment

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

CHPD would also appreciate extra language in R2.7 confirming that the required Corrective Action Plans are also extended to the spare equipment analysis and the maintenance outage requirements. This is CHPD's understanding, but this is not called out directly in the standard. We would appreciate language in R2.7 supporting NERC's expectation.

Likes 0	
Dislikes 0	

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer	Yes

Document Name	
Comment	

We feel that more explanation/guidance is needed to address what is and is not included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

Likes 0	
Dislikes 0	
Response	

Joyce Gundry - Public Utility District No. 1 of Chelan County - 3

Answer	Yes
Document Name	
Comment	

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

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Likes 0	
Dislikes 0	
Response	

Lauren Price - American Transmission Company, LLC - 1 - MRO,RF

Answer	Yes
Document Name	
Comment	

We proposed the following general recommendations.

- Footnote 13 – For the introductory sentence, we suggest; "If the following components of a Protection System are not redundant, then failure of one component must be evaluated".
- Footnote 13 – Add text to Footnote 13 to explicitly note in the standard that CTs and VTs used by Protection Systems are not to be considered as applicable to Category 5 events. We suggest to add wording (after the list of the four types of applicable comments) like, "Current instrument

transformers (CTs) and voltage instrument transformers (VTs) used by the Protection System are not be considered as applicable Protection System components for P5 category events.

Likes 0	
Dislikes 0	

Response

Steve Rawlinson - Southern Indiana Gas and Electric Co. - 1

Answer	Yes
Document Name	

Comment

We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	Yes
Document Name	

Comment

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

CHPD would also appreciate extra language in R2.7 confirming that the required Corrective Action Plans are also extended to the spare equipment analysis and the maintenance outage requirements. This is CHPD's understanding, but this is not called out directly in the standard. We would appreciate language in R2.7 supporting NERC's expectation.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE understands the Note Regarding Corrective Action Plans, the 84 month timeframe, is 84 months from the effective date of TPL-001-4, which was January 1, 2015. By January 1, 2022, the CAPs should no longer include Non-Consequential Load Loss and curtailment of Firm Transmission Service. Texas RE requests justification for that 84 month time period.

Texas RE recommends changing the name of the table with the extreme events to “Table 2”. It is confusing the Table with the planning events and the table with the extreme events are both named “Table 1” and many of the requirements refer to Table 1 even though they refer to different things.

Texas RE also noticed what appears to be a typo for MOD-032 in R1. There is a hyphen before MOD-032 and the font does not match the rest of the standard.

Likes 0	
Dislikes 0	
Response	

Sarah Gasienica - NiSource - Northern Indiana Public Service Co. - 5	
Answer	
Document Name	
Comment	

Please see comments of Joe O'Brien NIPSCO.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

In section 2.4., SRP recommends the last sentence be adjusted to look more like the last sentence of section 2.2. Instead of: “The following studies are required:” Change to: “Qualifying studies need to include the following conditions:”	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	TPL-001-5 Comments_Transmission.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Comments received from Kristine Ward, Seminole Electric Cooperative, Inc.

TPL-001-5 Comments

(1) In reviewing the edits to R1.1.2, SECI is concerned about the vagueness of those outages that must be modeled and whether such consultation will now require the RC to meet with each TP and PC separately within the FRCC on an annual basis.

(2) Given the changes to requirement R1.1.2, we believe there needs to be applicability in the standard to the Reliability Coordinator and not just the PC and TP. Also, since the SDT struck out the duration of six months in R1.1.2, there should be a time-frame around the length of transmission outages given some outages are only for a few hours, some for a day, a week, a month, etc., that may not be covering the year, season, or load level entities are assessing.

(3) In reviewing R1.1.2, the term “Transmission” appears to be need to be inserted into the term “Near-Term *Transmission* Planning Horizon” to be consistent with the defined term in the NERC glossary.

(2) Regarding the edits to R1.1.2, what happens if the RC, TP, or PC disagree as to which outages to include in the System models? Is it acceptable to the SDT if procedures are written whereby not all entities are in agreement with which outages to include?

(3) In R2.1.5, the SDT changed "studied" to "assessed". Can the SDT provide background on what is now expected with the term "assessed" differently than what was performed under the term "studied"?

(4) In R2.4.5, can the SDT elaborate on what is expected in, and how detailed, an entity's spare equipment strategy should be that is needed for TPL-001-5?

(5) In R2.4.5, the wording "The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment" opens entities up to major compliance interpretation issues as it's not certain that entities will evaluate ALL conditions that the System is expected to experience in our Planning Assessment, this needs to be further clarified by the SDT.

(6) P5, and footnote 13, was modified to cover non-redundant components of a Protection System. This is a substantial additional burden onto entities. Seminole requests the team to perform a cost effectiveness study concerning these additional edits.

Project 2015-10 Single Points of Failure

Consideration of Comments

Introduction

The standard drafting team (SDT) appreciates industry comments on the proposed Reliability Standard, TPL-001-5. The SDT considered the comments submitted during the initial posting of the proposed Reliability Standard, and has revised the standard accordingly.

The System Protection and Control Subcommittee (SPCS) and the System Analysis and Modeling Subcommittee (SAMS) conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Response to Comments – Summary Responses

The SDT has carefully reviewed and considered each stakeholder comment and has revised language where suggested changes are consistent with SDT intent and industry consensus. Also, several commenters suggested non-substantive language changes. The SDT has carefully considered each such comment and has implemented revisions to further clarify the language where needed. The SDT has addressed each comment and has provided below, in summary form, a response to each question.

Consideration of Comments

Project 2015-10 Single Points of Failure | TPL-001-5

Associated Ballots: 2015-10 Single Points of Failure TPL-001-5 IN 1 ST

There were ## sets of responses, including comments from approximately ## different people from approximately ## companies representing # of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

4. Do you agree with including Table 1 Footnote 13 a., “[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying”, and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs).

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

14. Do you have any other general recommendations/considerations for the drafting team?

Consideration of Comments – Summary Responses

Question 1: Associated Timetable and Annual Review Requirement R4 Summary Response

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

Extreme Event

There is a suggestion to remove implementation status and timetables, also extreme event 2e – 2h or three-phase fault followed by a protection failure is a low probability event and should have the same requirements as other extreme events.

SDT Response: The SDT agrees to remove implementation status and timetables. However, since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three -phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement.

PRC Standard Requirement

Why this requirement isn't part of the PRC standards, but is instead proposed for standard TPL-001?

SDT Response:

Project 2015-010 SAR does not allow for changes to any NERC standards other than TPL-001.

Requirement of CAP

There appears to be very little difference between 4.2.1 and 4.2.2 other than making a list and establishing an implementation timetable that would be meaningless if there is no intent to implement the solution. The current TPL-001-4 wording is sufficient unless there is a desire to require development and implementation of a Corrective Action Plan for certain events and circumstances, in which case, as previously suggested, the contingency should be moved from the extreme event category to a planning contingency category. Otherwise the wording in the current standard regarding extreme events that are found to result in cascading and/or instability should not be modified. There is confusion or lack of clarity around whether a CAP is required for the extreme event 2e – 2h.

SDT Response:

The SDT agrees to remove implementation status and timetables. However, since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three -phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement.

NERC Glossary Term

“Action” is not a defined term. SDT should write what they mean by “Action”.

SDT Response:
The SDT removed the reference to “Action” other than what is in the NERC Glossary for “Corrective Action Plan”.

CAP for Low Probability Event

It is not economically justifiable to require a CAP for low probability events. The SDT did not consider the cost and other factors.

SDT Response:
FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the cost of redundant relays, redundant trip coils, monitoring of communications and/or monitoring of DC supply is lower than the cost of transmission lines or transformers. Adding redundant protection improves the reliability of the Bulk Power System (BPS) at lower costs than other construction projects.

Shunt Devices

Add shunts to the list of 2e-2h list of extreme events.

SDT Response:
The SDT agrees with this and shunts were added to the next version of the standard. However, the SDT decided to make the disturbance a P8 planning event and requiring CAPs.

Transmission Planner Process

The review should follow the designated Transmission Planner’s existing processes that have already been developed. This review should be rolled into that process.

SDT Response:
The SDT agrees and made the event a P8 event which will follow similar reviews and processes as other planning events.

Adjustable Time Frame

Recommend the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

SDT Response:

The SDT agrees with this and it is addressed by making a three phase fault followed by a protection failure a P8 planning event.

Q1 Additional Comments

Additional Comment #1
Commenter does not agree with separating out the extreme event in 2e-2h for something between a CAP and no CAP.

SDT Response:
Standard Drafting team agrees with this comment and will be making a three-phase fault followed by a protection system failure a P8 planning event.

Additional Comment #2
The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, and that an adjustable time frame should be considered during subsequent reviews.

SDT Response:
The SDT agrees and made the event a P8 event which will follow similar reviews and processes as other planning events.

Additional Comment #3
No value added in extending the requirement to include event categories 2e-2h.

SDT Response:
FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended a three-phase faults be analyzed. Based on the reliability risk, the cost of redundant relays, redundant trip coils, monitoring of communications and/or monitoring of DC supply is lower than the cost of transmission lines or transformers. Adding redundant protection improves the reliability of the BPS at lower costs than other construction projects.

Additional Comment #4
There is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system. We would also like to point out that there is no corresponding directive from FERC in the SAR.

SDT Response:

FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed. The costs vs. benefit or resource requirements vs benefit is difficult to quantify since the reliability risk to the BPS is difficult to quantify in costs alone.

Question 2: Associated Timetable and Annual Review Requirement R4 Summary Response

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

Project Implementation

Language indirectly mandates implementation of construction of a project. The Requirement (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading. Language implies that action must be taken.

This aspect of the standard does not appear to meet the 'Clear Language' criteria in NERC's Standards Quality Review 'QR' Checklist because the requirement language as written does not assure that entities will be "able to arrive at a consistent interpretation of the required performance.

Commenters suggest removing 4.2.2.1 and 4.2.2.2 which may remove the interpretation issues of whether a CAP is required. This is a meaningless exercise if a project is not required.

Commenter recommends that the SDT remove the timetable language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

There is too much room for interpretation and suggests that a CAP is required.

SDT Response:
The SDT agrees and is removing Parts 4.2.2.1 and 4.2.2.2 but a three-phase fault followed by a protection failure is being moved to a P8 planning event.

Requirement of CAP

Language should be changed to a CAP is required or aligned with other extreme events.

Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.

SDT Response:
The SDT agrees and is making the 2e-2h a P8 planning event with a CAP requirement.

Project Implementation
If a capital project is the only feasible action, then it can be interpreted that implementation of the capital project is needed.

It appears that requiring an implementation plan and timetable is similar to a corrective action plan and is being mandated. Until the studies are done, it cannot be determined if any capital projects were included. In general, the utility will determine whether or not to address an issue based on risks and consequences of the event.

SDT Response:
The intent of the SDT was to have more analysis for a 2e-2h event as compared to other extreme events. It was not the intent of the SDT to require a CAP. However, due to industry comment and the risk of reliability to the BPS, the SDT has decided to make a three phase fault followed by a protection failure a planning events or P8.

Requirement of Project Implementation
Requirement 4.2.2 only requires "an evaluation of possible actions designed to prevent the System from Cascading". Requests that if the occurrence of an extreme event (2e-2h) were projected to cause cascading it should mandate actual implementation of actions identified as needed to prevent the System from Cascading.

SDT Response:
The SDT agrees and has put these into a P8 planning event.

Clarification of Wording
Recommend wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 related to extreme events for the steady state portion of the Planning Assessment.

Recommend that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

- 4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading.
- 4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity.

SDT Response:
The intent of the SDT was to have more analysis for a three phase fault followed by a protection failure as compared to other extreme events. It was not the intent of the SDT to require a CAP. Since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended 3-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed or a CAP requirement.

CAPs Limited to Protection System Projects

CAPs should be implemented to prevent Cascading; however, this should be limited to protection system projects.

SDT Response:
The SDT should not dictate to the TP or PC what the CAP has to be. The PC and/or TP needs to evaluate the best appropriate project to mitigate the violation.

Clarification of Wording

Parts 4.2.2, 4.2.2.1, and 4.2.2.2 “should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading.” In fact, its comparison of the language to the language of those requirements associated with a mandatory CAP indicates that the language and obligations under Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are actually more robust and stringent. This comparison is provided above in Question 1. Commenter does not agree with the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. Commenter submits that these requirements together amount to an actual implementation requirement, and that the language is consistent with a required/ mandatory CAP. Irrespective to whether or not a Transmission Planner believes a capital project is required to be implemented by Parts 4.2.2.1 and 4.2.2.2, the compliance will be determined by the language in the standard. If the language in Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are essentially the same as that for a CAP, the requirement is essentially equivalent to CAP.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, to clarify the intent stated in this question, Commenter recommends the following revisions to the proposed language for Parts 4.2.2, 4.2.2.1, and 4.2.2.2:

4.2.2 If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, the TP and/or PC shall:

4.2.2.1 Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.

4.2.2.2 Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

SDT Response:
The intent of the SDT was to have more analysis for a three-phase fault followed by a protection failure as compared to other extreme events. It was not the intent of the SDT to require a CAP. However, the SDT has decided to make a three-phase fault followed by a protection failure P8 planning event and require a CAP. This is because FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS.

Q2 Additional Comments

Additional Comment #1
Commenter believes that analyzing system performance when subject to "Extreme Events" is meant to provide a sense of where instability and/or Cascading could occur for the PC and/or TP to assess what actions could be developed to mitigate or reduce the potential impact. Such actions generally involve positioning the BES, adjusting outage plans, implementing operations strategies, developing a safe posture and preparing for resiliency plans, but not any capital investment projects. Note that this does not preclude the responsible entity from implementing any of these actions in its sole discretion, but it should not be mandated. Capital projects to address operational circumstances should not be mandated in a TPL standard. Further, requiring capital projects would exceed the scope of FERC Order 754 and 786 as well as the SAR.

SDT Response:
Per the NERC Glossary definition of CAP, a capital project is not required if implementing operations strategies mitigate the performance violation. The language in Parts 4.2.2.1 and 4.2.2.2 was intended to include operational strategies not just capital projects. However, the SDT decided to remove 4.2.2.1 and 4.2.2.2 and make a three phase fault followed by a protection failure a P8 planning event.

Additional Comment #2
Recommend the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

SDT Response:
The SDT removed Part 4.2.2.2 and is making the three-phase fault followed by a protection failure a P8 planning event. The SDT also developed an implementation plan for TPL-001-5.

Additional Comment #3
Oftentimes the capital project may be a relay upgrade project which is relatively low cost compared to the benefits.

SDT Response:
The SDT agrees.

Question 3: Associated Timetable and Annual Review Requirement R4 Summary Response

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

Requirement Omission

Commenter believes that the omission in 4.2 is necessary as there are not performance requirements in the Table for Extreme Events.

Commenter agrees that a requirement to ensure that Cascading does not occur in subsequent Planning Assessment given extreme events 2e-2h in the stability column should be omitted

SDT Response:
The SDT appreciates these comments. However, due to other comments received by the industry and since FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS, the SDT has decided to require a CAP for a three-phase fault followed by a protection failure results in Cascading or instability. This has been also made into a P8 event.

Implementation Timetable

Commenter disagrees with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.

SDT Response:
The SDT appreciates these comments. However, due to the following:

- other comments received by the industry
- because FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS

The SDT has decided to require a CAP for a three-phase fault followed by a protection failure.

System Performance

Commenter believes that requirement 2.7 would cover system performance for the R4 requirements.

The planned system should always meet the performance requirements in Table 1 in any Planning Assessment that is performed. To the extent a Corrective Action Plan is developed for issues identified in one Planning Assessment and the issues go away in subsequent Planning Assessments due to changes in load forecasts or other drives of the original issue, elimination or modification of the Corrective Action Plan in the subsequent Planning Assessment should certainly be allowed, but the language above that states “the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments” seems unnecessary since the Table 1 requirements apply to all Planning Assessments.

If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.

SDT Response:
The SDT agrees and has removed the confusion by making the three-phase fault followed by a protection failure a P8 planning event requiring a CAP to meet the associated performance requirements with Implementation Plan.

Q3 Additional Comments

Additional Comment #1
CAPs should not be required for a three-phase fault followed by a protection failure.

Commenter agrees that a corrective action plan should not be required for an extreme event. The 2e through 2h events referenced in Requirement R4, Part 4.2.2, however, should be planning events and, accordingly, corrective action plans should be required for them.

SDT Response:
The SDT disagrees, this is due to the fact that FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS. This is also supported by other industry comments. The SDT has decided to make a three-phase fault followed by a protection failure a P8 planning event.

Additional Comment #2
Commenter agrees that extreme events do not need the same level of requirements as Planning Events.

SDT Response:
The SDT disagrees, this is due to the fact that FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS. This is also supported by other industry comments. The SDT has decided to make a three-phase fault followed by a protection failure a P8 planning event.

Additional Comment #3
As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the

implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

SDT Response:
The SDT agrees and decided to make a three-phase fault followed by a protection failure a P8 planning event which removed much of the confusion in the industry.

Question 4: Footnote 13
Summary Response

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

The SDT paid considerable attention to the depth of the industry comments received regarding Footnote 13 (Questions 3, 4, and 5) and has sought to address general and specific industry comments with the following response. The most common comment noted the discrepancy between red-line version and clean version of the proposed draft; the SDT agrees and has corrected the Footnote 13 bullets to "a,b,c,d", not "1,2,3,4". One theme that was communicated by industry was to desire specificity about the Protection System components that must be redundant. The SDT seeks to make clear that the draft Footnote 13, as well as changes to the P5 and extreme events, do not prescribe any level of redundancy. Footnote 13 is not a definition of redundancy. On the contrary, Footnote 13 identifies the components of a Protection System that should be considered for redundancy and failures that may lead to Delayed Clearing, when Planning Coordinators and Transmission Planners simulate Contingencies for the purpose of analysis that supports TPL-001-5 annual Planning Assessments.

Sudden Pressure Relaying
Several stakeholders suggested removing "e.g. sudden pressure relaying" from Footnote 13a. It was suggested that this confusing language can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

SDT Response: The SDT agrees that specific reference to sudden pressure relaying confuses the purpose of Footnote 13a, which is to focus on an alternative that provides comparable Normal Clearing times to a single protective relay which responds to electrical quantities. The proposed draft has been revised to omit this language.

Single Protective Relay Action
Similar to the comments suggesting that the SDT should define redundancy, some industry commenters suggested that the SDT should specify the actions taken by a single protective relay, instead of identifying

individual Protection System components when considering for redundancy under this standard. Relatedly, it was suggested that reference to a single protective relay should apply to a relay unit and not a relay element (multiple relay elements within a single relay unit are not redundant given a common failure, e.g., power supply).

SDT Response: The Footnote 13a in the proposed TPL-001-5 standard specifies the non-redundant components of a Protection System that the Planning Coordinator and Transmission Planner must consider. Therefore the PC and TP must determine how to properly simulate failures of non-redundant components of a Protection System, given the consideration of their constituent Protection Systems. The SDT does not desire to propose language that is overly prescriptive and instead desires that the focus remain on failures of non-redundant components of a Protection System that must be simulated for Delayed Fault Clearing.

Question 5: Footnote 13
Summary Response

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

Defining "Monitored" and "Reported"

The most-frequently provided industry comment to Question 5 indicated that "monitored" and "reported" were not sufficiently defined, such as in PRC-005-6 Tables 1-2, 1-4, and 2. Specifically, a desire was expressed for a reporting time stipulation when considering redundancy and how quickly corrective action could be enacted.

SDT Response: The SDT agrees with the industry comments and has modified the proposed Footnote 13b and 13c to language similar to that in the Standards Authorization Request (SAR) proposed following the joint SAMS/SPCS report: "not monitored such that alarms are centrally reported (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)." The SDT simplified the suggested language to "not monitored or not reported at a Control Center." It is well understood that a Control Center hosts operating personnel that monitor the Bulk Electric System (BES) in real-time to perform reliability tasks, so the SDT did not believe specifying a reporting or correction initiation timeframe was necessary. Separately, reference to a single station dc supply was added by the SDT to 13c to align with the Protection System defined term.

Communication Systems

Some industry commenters suggested that communication systems referenced by Footnote 13b should be limited to just those used for critical/crucial Normal Clearing times.

SDT Response: Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential single point of failure (SPF) components of Protection Systems. Although the SAMS/SPCS report noted that a SPF in a communication system posed a lower level of risk, the drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all leading to Delayed Clearing, must be considered as part of non-redundancy. The SDT concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the BES is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard. Further, the SDT does not believe that critical or crucial clearing times are pertinent to the Planning Coordinator or Transmission Planner when determining how long to simulate a fault until it clears. In other words, the critical clearing time is a result of analysis, not a precondition of the analysis (such as considerations of Protection System component redundancy).

Protective Functions

For consistency amongst the non-redundant components of a Protection System that must be considered as part of Footnote 13, the protective functions associated with a single dc supply should refer to Normal Clearing.

SDT Response: The SDT agrees with the industry comment and has added reference to Normal Clearing to Footnote 13c and 13d for consistency and clarity.

Q5 Additional Comments

Additional Comment #1

Some industry stakeholders believe that preventive maintenance per PRC-005 provides reasonable and sufficient assurance for detection and handling “open circuit” conditions, implying that this stipulation in Footnote 13c should be omitted.

SDT Response: The SDT agrees that PRC-005 establishes maintenance practices that may significantly reduce the likelihood of a single point of failure in a dc supply serving protective functions, however this may not eliminate its occurrence and may lead to Delayed Fault Clearing. The SDT proposed Footnote 13c is consistent with the SAMS/SPCS report recommendations and the Project 2015-10 SAR.

Question 6: Footnote 13
Summary Response

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?

Definition of Control Circuitry

The most common industry comments regarding Footnote 13d suggested the definitions of control circuitry remains vague; that the demarcation of supply and control circuitry was vague; and, suggested aligning the Footnote 13d language closer to that recommended in the SPCS report.

SDT Response: The SDT intended single DC supply to refer to the entire set of equipment that comprises the DC source supplying power to Protection System components necessary for Normal Clearing. In other words, the SDT sought to specify that, within the entire set of equipment comprising the single DC supply, a failure of a piece of equipment that causes the single DC supply to be unable to source power to the protective functions necessary for Normal Clearing must be considered as part of Footnote 13. Relatedly, the SDT agrees that a typical station battery bank is only one part of the single DC supply. Further, a failure of a station battery may be masked for short time by the AC-sourced station battery charger. However, the SDT did not prescribe specific DC supply design configurations. Instead, the SDT emphasized that the single DC supply must be considered for susceptibility to SPF as part of Footnote 13. To clarify Footnote 13d, the SDT has revised it to explicitly include auxiliary relays and lockout relays in the control circuitry, as well as specify the circuitry components to consider extends through and including the trip coils.

Trip Coil Failure

Some industry commenters suggested that a failure in a non-redundant single trip coil that results in a breaker not acting properly is covered by breaker failure (P4 events). Similarly, it was suggested to replace references to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity given that this is more severe and simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4.

SDT Response: While trip coil monitoring devices are commonly available to give awareness of potential trip coil failure, the SDT believes monitoring trip coil failure or relay trouble indication is insufficient to ensure that a SPF is not present within a single control circuit. Similarly, DC undervoltage relaying or other control circuit continuity monitoring may indicate a problem with part of the DC control circuit, but may not give awareness of SPF risks such as serial tripping devices (ANSI #86 and #94 devices). Therefore, The SDT did not incorporate a monitoring provision into Footnote 13d and intends for non-redundant components within the DC control circuitry of a Protection System to be considered as part of Footnote 13.

Question 7: Known Outages
Summary Response

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those *selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs)?*

Selecting Outages in Consultation with Reliability Coordinator

The majority of industry respondents commented that selecting outages in consultation with their Reliability Coordinators was problematic and offered alternative suggestions.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Roles and Responsibilities for Reliability Coordinator and Transmission Planner

Several industry respondents commented that if the coordination language is retained clarity needs to be added to better define "consultation". The roles and responsibilities need to be spelled out including establishing criteria for outages and resolving conflicts between the RC and TP.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Outages in the Near Term Planning Horizon

Several industry commenters believed that outages in the near term planning horizon should remain within the auspicious of the TPL standard and not in the IRO arena.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

IRO-017

Several industry commenters believed IRO-017 should be the primary vehicle to include planned outages in the near term planning horizon.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Six Month Outage Duration

Several industry commenters suggested the directive could be addressed by changing the 6 month outage period to something like "outages spanning the entire season under study" (or other outages as determined by the TP/PC)

SDT Response: The SDT believes that the time duration of a known outage does not necessarily correlate with the significance of outage. The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1 part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Q7 Additional Comments

Additional Comment #1

Several commenters requested event clarification – standard specifies that only P1 events should be run on the cases with these outages in place, do we remove them for the other studies

SDT Response: Requirement R2, Part 2.4.3 requires new maintenance outages that have met the TP/PC requirement for studies to be conducted for P1 events only. How, or if, an entity choses to incorporate outages when performing additional analysis is not a NERC TPL standard requirement.

Additional Comments #2

One commenter responded with a minor changes Lower-case the term "Off Peak".

SDT Response: The capitalized term "Off-Peak" are in Parts 2.1.3 and 2.4.3 that have already been approved by industry. The SDT is not proposing to change those requirements.

Question 8: Applicability
Summary Response

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

Regional Differences

The range of industry comments to question 7 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The majority of industry respondents commented that Reliability Coordinator involvement is not necessary (this standard only applies to TP and PCs) or move RC duty details to IRO-017 (then delete from TPL).

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Reliability Coordinator Applicability

The range of industry comments to question 7 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The significant minority of industry respondents commented that if “consultation” with RC is not removed, then add the RC to the applicability portion.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

Q8 Additional Comments

Several comments that were duplicative of comments received in question 7 including-Specify roles and responsibilities; Revise IRO-017-1 to address FERC directive; and Move the reporting requirement in IRO-017-1 R3 to TPL-001-5 instead.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon. Modifications to IRO-017 are not within the scope of the approved Project 2015-10 SAR.

Question 9: Outage Coordination
Summary Response

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

Regional Differences Concerning Outage Coordination (IRO-017)

The range of industry comments to question 7 and 9 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The majority of industry respondents pointed to IRO-017 to tighten up coordination of significant outages that are less than 6-month duration; expressed that coordination is already being done through various mechanism; or the directive predates IRO-017-1 and isn’t relevant anymore.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon. Modifications to IRO-017 are not within the scope of the approved Project 2015-10 SAR.

Regional Differences Concerning Outage Coordination (MOD-032) and Applicability of Transmission Owner and Generator Owner

The range of industry comments to question 7 and 9 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. Several industry respondents suggested to modify MOD-032 such that known outages are included in the data submitted for TPL.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of known maintenance outages in the near term planning horizon. MOD-032 does not specifically address how outages are communicated, however the TP and PC may require Transmission Owner (TO) and Generator (GO) to provide outage related data.

Question 10: Implementation Plan
Summary Response

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

Existing substations and new substations

There is a suggestion to grandfather existing substations and any new requirements would apply to new substations when they are built.

SDT Response: FERC Order No. 754 analysis and the resultant SPCS and SAMS report indicated there is a reliability risk to the BPS caused by single point of failures with existing Protection Systems. These reliability concerns need to be addressed for the existing and planned Protection Systems. The purpose of the Implementation Plan is to allow for identification and mitigation of all Protection System single points of failures to meet performance requirements, whether existing or planned.

Proposed P5 event / footnote 13

Some commenters disagree with a 36 month implementation period because of the ambiguity in the proposed P5 event / footnote 13. Additionally, larger utilities suggested the Implementation Plan be extended to 48 month.

SDT Response: The SDT has addressed ambiguity concerns in Footnote 13 language previously in Questions 4 through 6 and has modified Footnote 13. The SDT feels that 36 months are adequate to complete first set of studies. The implantation plan allows for additional time to develop a CAP.

Stability Analysis for Spare Equipment

Addressing all new requirements except 4.2 and 2.7 which would include the stability analysis for spare equipment and developing a process for selecting known outages and establishing coordination with protection engineers. Stability analysis is the most time consuming part of the planning assessments.

SDT Response: The SDT agrees and has revised the implementation.

Question 11: Implementation Plan Summary Response

11.Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

The Additional 24-months Too Short

The additional 24-months to implement any resulting Corrective Action Plans for P5 events may be too short.

SDT Response: The additional 24 months is to only identify appropriate Corrective Action Plan and establish the associated timetables for completion.

72-months Implementation Recommended

A 72-month implementation plan would be preferable for the development of Corrective Action Plans to address newly-added studies involving single point of failure on Protection Systems.

SDT Response: The SDT disagrees. The revised implementation period provides Planning Coordinators and Transmission Planners with 36 months to update their annual Planning Assessments to include the new System models and studies required by the standard. 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. Furthermore, in the event that an Operating Procedure, Non-Consequential Load Loss or curtailment of Firm Transmission Service is insufficient to meet performance requirements, the implementation plan includes an additional 36 months to meet the performance requirements of Table 1 for revisions to P5, and the addition of P8.

Question 12: Cost Effectiveness Summary Response

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (see Cost Effectiveness Background Document)

CAP for Extreme Events Low Probability Event not economical:
Several industry comments indicate that proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status for the extreme stability 2e-2h event contingencies go significantly beyond obligations for all other extreme events, and it is not economically justifiable and cost effective to require a CAP for low probability events.

SDT Response: FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no cascading allowed. In view of the addition of P8 events, industry stakeholders will have the opportunity to re-evaluated cost effectiveness in the next posting.

Six Month Outage Duration review
Several industry comments indicate that Transmission Planners (TP) performing an annual study review of outages less than six months have redundancies associated with outage coordination and does not represent a cost effective approach.

SDT Response: The SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of known maintenance outages in the near term planning horizon. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

Q12 Additional Comment
Requiring a fully-redundant control circuitry without due consideration of status monitoring combined with periodic independent component testing is duplicative for system reliability and is not the most cost-effective option to address the FERC directive. The cost-effective solution is to include the allowance for excluding control circuitry with monitoring from Footnote 13d.

SDT Response: The SDT disagrees with the comment because continuity monitoring of the control circuits may not give awareness of single point of failure risks. Therefore, the SDT did not incorporate a monitoring provision into Footnote 13d and intends for non-redundant components within the control circuitry of a Protection System to be considered as part of Footnote 13d. Please refer to Question 6 response.

Question 13: Governing Documents
Summary Response

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

Coordination between the TPL-001-5 and the new FAC-015 standards

The industry consider that the new FAC-015 requirements with respect to the system operating limits should be used in planning assessments and need to be included within TPL-001-5.

SDT Response: The new FAC-015 requirements with respect to the system operating limits to be used in planning assessments cannot be included within TPL-001-5 because these are not part of the objectives of the Project 2015-10 Single Point of Failure SAR. The request to coordinate the standards FAC-015 and TPL-001 with respect to the system operating limits to be used in planning assessments belong in a new SAR and must be addressed to NERC.

Multiple NERC definitions of acceptable types of redundancy of Protection System

The difference between the protection system redundancy definition in the 2009 NERC document "Protection System Reliability – Redundancy of Protection", as well as the redundancy requirements described in PRC-012-2, and theTPL-001-5 footnote 13 will likely cause confusion in industry.

SDT Response: There is a difference between the Protection System redundancy definition in the documents mentioned above and footnote 13 of TPL-001-5. The purpose of the TPL-001 modified footnote 13 is to specify which non-redundant components of a Protection System to be considered for the Single Point of Failure analysis. It was not intended to define the Protection System redundancy. The inclusion of some elements of a protection system but not all, aligns with the SAMS and SPCS recommendations.

Disconnection between operations and planning

The IRO-017 already defines the process for studying outages within the Operational Planning Horizon. The industries consider that the maintenance outages should be evaluated in the Operating Horizon, if not, a conflict can be created between the two standards TPL-001-5 and IRO-017-1.

SDT Response: The planned outages studied in TPL-001 are provided to the RC through the Near-Term Planning Assessment to jointly develop solutions for identified issues or conflicts with planned outages as part of the outage coordination process of IRO-017. Therefore, there is no conflict between TPL-001 and IRO-017.

Implementation of corrective actions might require capital projects and additional infrastructure

Requiring implementation of corrective actions which include capital projects and additional infrastructure would contradict the Energy Policy Act of 2005 and directly conflicts with some provincial regulations.

SDT Response: Reliable operation of the BPS is required by the Federal Legislation. Requirement 2.7.1 allows solutions to be developed which don't necessarily require construction of additional generation or transmission capacity. The SDT proposes to add a new P8 Planning Event to "Table 1 – Steady State and Stability Performance Planning Events", in order to include a 3-phase fault and failure of a non-redundant component of a Protection System.

Question 14: Other Considerations
Summary Response

14. Do you have any other general recommendations/considerations for the drafting team?

Paragraph 81

Requirements R5, R6, R7, and R8 fall under such criteria

SDT Response: The SDT disagrees that Requirement 5, 6, 7,-8 meet the Paragraph 81 criteria.

NERC Project to address FERC Directives

Commenter suggests that objectives outlined in the FERC Directives could be accomplished without the need to revise the standard in this manner. The objectives could be met in the form of a NERC project or initiative requesting that these assessments/studies be done in 10% or 20% intervals over a set period of time, and the data submitted to NERC for its review. We feel that requiring these objectives in a standard, with the ever changing configuration of the system, would require that this work as proposed be done every year, which would be extremely burdensome. We recommend that the studies and assessments that will be required would be better suited outside of the NERC standards.

SDT Response: Thank you for your comment. A standards project was required to address the FERC directives.

TPL-001-5 R4, Part 4.2.2.2 including extreme event 2e-2h

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 1-3. Additionally commenters proposed specific language suggestions for certain sections.

SDT Response: When possible the SDT considered the language suggestions. Please see the revised standard to see if your specific suggestion or a close proximity was incorporated into the new language. For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 1-3, please see the comments from the SDT provided in Questions 1-3.

Economic Impacts of Extreme Events

Commenter suggested the drafting team should revisit the economic impacts of the proposed changes, specifically those concerning extreme events.

SDT Response: See response for Question 12.

TPL-001-5 Footnote 13

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 4-6. Additionally commenters proposed specific language suggestions for certain sections.

SDT Response: When possible, the SDT considered the language suggestions. Please see the revised standard to see if your specific suggestion or a close proximity was incorporated into the new language.

For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 4-6, please see the comments from the SDT provided in Questions 4-6.

TPL-001-5 TP/PC Coordination with RC, Outage Coordination

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 7-9. Additionally commenters proposed moving requirements both to and from IRO-017. Several stakeholders expressed concerns that selecting outages in consultation with their Reliability Coordinators was problematic and offered alternative suggestions.

SDT Response: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. Those differences contribute to a legitimate difficulty in designing a cost-effective continent wide standard addressing the FERC directive. For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 7-9, please see the comments from the SDT provided in Questions 7-9.

Spare Equipment Strategy in Stability Study

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

SDT Response: The existing language in the standard requires a CAP. Loss of long-lead items are studied. No changes to the language is necessary.

Monitoring of Protection System

If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6.

SDT Response: See response to Question 6.

Spare Equipment Strategy

The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a "more severe System impact" standard of performance. This begs the question, "More severe than what?

SDT Response: This exists in the current of the standard and it is up to the PC and TP to determine what is more severe.

Linking Standards

Perhaps this is an opportunity to link TPL-001-5 and PRC-023-4 into a single assessment?

SDT Response: the TP and PC can take the Planning Assessment and apply to PRC-023-4. No link is required

Models Developed under MOD-032

The timing of models developed under MOD-032 sometime make it difficult to have an exact "year five" model. R2.1.1 could be more flexible – similar to 2.1.2.

SDT Response: The TP and PC can request data for any year that they need.

Standard Revision

In section 2.4., the last sentence should be adjusted to look more like the last sentence of section 2.2.

SDT Response: Thank you for your comment. This is not in the scope of the SAR.
NERC Glossary of Terms

Footnote 12

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

SDT Response: Thank you for your comment. This is not in the scope of the SAR.

Revision of PRC Standard

An alternative first step should have been in a PRC Standard to address the concerns in reference to Single Point Failure. Furthermore, there could be a potential disconnect between the Transmission Planner and Protection Engineers by placing this only in a Planning Standard. Also, we recommend that the draft team includes the Transmission Owner (TO) and Generator Owner (GO) in the applicability section, along with an additional requirement specifying that the TO and GO should provide pertinent data (e.g., contingency definitions, elements tripped) upon request by the PC in order to assess the impact of Single Point of Failure in their assessments.

SDT Response: Thank you for your comment. This is not in the scope of the SAR.

Industry Segments

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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 MOD-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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

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 expected to produce more severe System impacts on its portion of the BES, 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, Part2.6. 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 expected to produce more severe System impacts on its portion of the BES, 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, Part2.6 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 Schemes.
- 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. 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.

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

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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 P8) 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.	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 P8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P8) 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 base its studies on computer simulation models using data provided in Requirement R1.
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.	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 P8) in Table 1. OR	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 P8) in Table 1. OR	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 P8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (P0 through P8 events): 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 (P0 through P7 events 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 (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	3Ø	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault.
f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances</td></tr>
</table>

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	

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: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. 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 at a Control Center; c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit; d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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

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

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.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-~~4~~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:** 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~~

- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

~~**B. Requirements**~~

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 MOD-~~010 and MOD-012 standards~~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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with ~~a~~ the selected known outage(s); and

~~**1.1.1.1.**~~**1.1.2.2.** Does not exclude known outage(s) solely based upon the outage duration~~ of at least six months. ~~.

~~**1.1.2.**~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~**1.1.3.**~~**1.1.4.** Real and reactive Load forecasts.

~~**1.1.4.**~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.5.**~~**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 expected to produce more severe System impacts on its portion of the BES, 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 ~~studied~~assessed. The ~~studies~~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, Part2.6. 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 expected to produce more severe System impacts on its portion of the BES, 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.

~~**2.4.3.**~~**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.

~~2.4.4.~~**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, Part2.6 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 Schemes.
- 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.

~~**M1.**~~**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~~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. 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.

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]*

~~M2.~~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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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~~032 standards and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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 P~~7~~8) 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.	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 P~~7~~8) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P~~7~~8) 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 base its studies on computer simulation models using data provided in Requirement R1.
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.	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 P~~7~~8) in Table 1. OR	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 P~~7~~8) in Table 1. OR	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 P~~7~~8) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability~~:~~ (P0 through P8 events): 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~~:~~ (P0 through P7 events 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~~:~~ (P1 through P7 events only): j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	3Ø	EHV, HV	Yes	Yes

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.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø internal breaker fault.
   f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	

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. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. 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 at a Control Center; c. A single station dc supply associated with protective functions ~~or types: pilot (#85), distance (#21), differential (#87), current (#50, 51~~required for Normal Clearing, and ~~67),~~that single station dc supply is not monitored or not reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67),~~ and ~~tripping (#86, & 94).~~open circuit; d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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.

~~C. Measures~~

~~**M3.** 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, 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.~~

~~**M4.M1.** 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.~~

~~**M5.** 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.~~

~~**M6.M1.** 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.~~

~~**M7.M1.** 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.~~

~~**M8.** 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.~~

~~**M9.** 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.~~

~~**M10.M1.** 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.~~

~~D. Compliance~~

~~**1. Compliance Monitoring Process**~~

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

~~Regional Entity~~

~~**1.2 Compliance Monitoring Period and Reset Timeframe**~~

~~Not applicable.~~

~~1.3 Compliance Monitoring and Enforcement Processes:~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~

~~Spot Checking~~

- ~~Compliance Violation Investigations~~

~~Self-Reporting~~

- ~~Complaints~~

~~1.4 Data Retention~~

~~The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.~~

~~The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.~~

- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.~~
- ~~The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.~~
- ~~The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.~~
- ~~The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.~~

~~The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.~~

~~If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.~~

~~1.5 Additional Compliance Information~~

~~None~~

2. ~~Violation Severity Levels~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~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 standards and other sources, including items represented in the Corrective Action Plan.~~
~~R2~~	~~The responsible entity failed to comply with Requirement R2, Part 2.6.~~	~~The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.~~	~~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.~~	~~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.~~
~~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.~~	~~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.~~	~~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 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.~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~OR~~ ~~The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.~~	~~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.~~	~~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 base its studies on computer simulation models using data provided in Requirement R1.~~
~~**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.~~	~~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~~ ~~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 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~~ ~~The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.~~	~~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~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~
~~**R5**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.~~
~~**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.~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**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.~~
~~**R8**~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.~~ ~~OR~~ ~~The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.~~ ~~OR~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.~~ ~~OR~~ ~~The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~related need who requested the Planning Assessment in writing.~~

~~E.A. Regional Variances~~

~~None.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~February 8, 2005~~	~~BOT Approval~~	~~Revised~~
~~0~~	~~June 3, 2005~~	~~Fixed reference in M1 to read TPL-001-0 R2.1~~ ~~and TPL-001-0 R2.2~~	~~Errata~~
~~0~~	~~July 24, 2007~~	~~Corrected reference in M1. to read TPL-001-0~~ ~~R1 and TPL-001-0 R2.~~	~~Errata~~
~~0.1~~	~~October 29, 2008~~	~~BOT adopted errata changes; updated version number to "0.1"~~	~~Errata~~
~~0.1~~	~~May 13, 2009~~	~~FERC Approved – Updated Effective Date and Footer~~	~~Revised~~
~~1~~	~~Approved by Board of Trustees February 17, 2011~~	~~Revised footnote 'b' pursuant to FERC Order RM06-16-009~~	~~Revised (Project 2010-11)~~
~~2~~	~~August 4, 2011~~	~~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.~~	~~Project 2006-02 – complete revision~~
~~2~~	~~August 4, 2011~~	~~Adopted by Board of Trustees~~	
~~1~~	~~April 19, 2012~~	~~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 has been directed to revise footnote 'b' in~~	

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
		~~accordance with the directives of Order Nos. 762 and 693.~~	
~~3~~	~~February 7, 2013~~	~~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.~~	
~~4~~	~~February 7, 2013~~	~~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.~~	
~~4~~	~~October 17, 2013~~	~~FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).~~	
~~4~~	~~May 7, 2014~~	~~NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.~~	~~Revision~~
~~4~~	~~November 26, 2014~~	~~FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.~~	

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017

Anticipated Actions	Date
45-day formal comment period with additional ballot	February 2018
10-day final ballot	May 2018
Board adoption	August 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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 MOD-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) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities.

~~1.1.3.~~1.1.4. Real and reactive Load forecasts.

~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange.

~~1.1.5.~~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 expected to produce more severe System impacts on its portion of the BES, 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, Part2.6. 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 expected to produce more severe System impacts on its portion of the BES, 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, Part2.6 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 Schemes.
- 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. 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.

~~**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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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 P8~~7~~) 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.	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 P8~~7~~) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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 P8~~7~~) 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 base its studies on computer simulation models using data provided in Requirement R1.
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.	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 P8~~7~~) in Table 1. OR	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 P8~~7~~) in Table 1. OR	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 P8~~7~~) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability (P0 through P8 events): 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 (P0 through P7 events 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 (P1 through P7 events only):** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

<table>
<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>
<tr><td rowspan="2">P3
Multiple Contingency</td><td rowspan="2">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]</td><td>3Ø</td><td rowspan="2">EHV, HV</td><td rowspan="2">No[9]</td><td rowspan="2">No[12]</td></tr>
<tr><td>5. Single pole of a DC line</td><td>SLG</td></tr>
<tr><td rowspan="3">P4
Multiple Contingency
(Fault plus stuck breaker[10])</td><td rowspan="3">Normal System</td><td rowspan="2">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</td><td rowspan="2">SLG</td><td>EHV</td><td>No[9]</td><td>No</td></tr>
<tr><td>HV</td><td>Yes</td><td>Yes</td></tr>
<tr><td>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, HV</td><td>Yes</td><td>Yes</td></tr>
</table>

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
P8 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	3Ø	EHV, HV	Yes	Yes

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.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. 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[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. ~~d.~~ 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. ~~3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~ ~~e. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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.	~~f. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.~~ ~~g.~~d. ~~3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Cleari~~ ~~h.~~e. 3Ø internal breaker fault. ~~i.~~f. 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: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~; b. 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 at a Control Center; c. A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit; d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

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.

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, relating to:
    - modeling known outages with a duration of less than six months; and
    - adding stability analysis for the outage of major Transmission Equipment with a lead time of one year or more.
- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations

This implementation plan provides 36 months until the effective date of the Standard, providing Planning Coordinators and Transmission Planners with time to update their annual Planning

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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~~, relating to:
    - modeling known outages with a duration of less than six months; and
    - adding stability analysis for the outage of major Transmission Equipment with a lead time of one year or more.
- 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~~This implementation ~~period for TPL-001-5~~plan provides 36 months until the effective date of the Standard, providing 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~~procedure or technical rationale for ~~coordinating with the Reliability Coordinator which~~selecting known outages of generation ~~of~~and 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~~this implementation plan includes an additional 24-month period for the development of Corrective Action Plans (CAPs) under TPL-001-5 to address newly-added studies for P5 and P8 planning events involving single points of failure on Protection Systems.

This extended implementation period for the part of Requirement R2, Part 2.7 that states: "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", acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed.

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~~CAP actions and establish the associated timetables for completion. This includes~~:~~

- ~~Any~~ any necessary ~~Corrective Action Plans to address Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any necessary Corrective Action Plans~~CAP to address System performance issues for studies involving Table 1 Category P5 and P8 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 protective functions, which is not monitored or not reported~~

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

Lastly, the provisions related to ~~Corrective Action Plans~~CAP 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 ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items ~~2, 3,~~b, c, and d and 4P8

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

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~~b, c, and 4d or P8 until 24 months after the effective date of Reliability Standard TPL-001-5.

~~**Note Regarding Corrective Action Plans**~~

For CAPs developed to address failures to meet Table 1 performance requirements for P5 or P8 events only, Transmission Planners and Planning Coordinators shall not be required to comply with the section of Requirement R2, Part 2.7 that states: "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**", until 96 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding CAPs

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~~CAP 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 without CAPs for revised P5 or P8 in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall ~~complete~~develop any required ~~Corrective Action Plans~~CAP under ~~Requirement R4, Part 4.6 and~~ 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~~b, c, and ~~4~~d and P8 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.

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 procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- 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, this implementation plan includes an additional 24-month period for the development of Corrective Action Plans (CAPs) under TPL-001-5 to address newly-added studies for P5 and P8 planning events involving single points of failure on Protection Systems.

This extended implementation period for the part of Requirement R2, Part 2.7 that states: "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", acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed.

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 CAP actions and establish the associated timetables for completion. This includes any necessary CAP to address System performance issues for studies involving Table 1 Category P5 and P8 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 non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

Lastly, the provisions related to CAP 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 b, c, and d and P8

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 b, c, and d or P8 until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for P5 or P8 events only, Transmission Planners and Planning Coordinators shall not be required to comply with the section of Requirement R2, Part 2.7 that states: "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**", until 96 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding CAPs

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, CAP 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 without CAPs for revised P5 or P8 in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall develop any required CAP 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 b, c, and d and P8 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.

Unofficial Comment Form

Project 2015-10 Single Points of Failure TPL-001

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2015-10 TPL-001-5 – Transmission System Planning Performance Requirements**. Comments must be submitted by **8 p.m. Eastern, Monday, April 23, 2018.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. Do you agree with the creation of the proposed P8 event?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed implementation plan?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed revisions to TPL-001-4?

   ☐ Yes
   ☐ No

   Comments:

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

   ☐ Yes
   ☐ No

   Comments:

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 instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

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:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

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.

Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **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. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **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-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.	<u>Requirement R1 body</u>. Updated referenced standard number in body of requirement. <u>Requirement R1 Part 1.1.2</u> Consistent with FERC Order 786 Para 40, the six-month threshold that could exclude planned maintenance outages is eliminated. Additionally, the addition of Near-term Planning Horizon aligns this requirement with IRO-017-1 Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. **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	1.1.2. Known -outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum: ~~1.1.2.1.~~ ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events	Assessment for the Near-Term Transmission Planning Horizon. Requirement R1 Parts 1.1.2.1, 1.1.2.2, and 1.1.2.3 Substantial regional differences exist for outage coordination methods and procedures, making it difficult to define specific known outage selection criteria pertinent to all. Therefore, considering the NERC SAMS recommendations, selection of known outages in the Near-Term Planning Horizon were limited to three primary considerations. Requirement R1 Part 1.1.2.1 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss (FERC Order 786, Paragraph 41).

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	in Table 1 when concurrent with the selected known outage(s); and ~~1.1.2.2.~~ Does not exclude known outage(s) solely based upon the outage duration. ~~1.1.2.~~1.1.3. New planned Facilities and changes to existing Facilities. ~~1.1.3.~~1.1.4. Real and reactive Load forecasts. ~~1.1.4.~~1.1.5. Known commitments for Firm Transmission Service and Interchange. ~~1.1.5.~~1.1.6. Resources (supply or demand side) required for Load.	Therefore, System models shall represent known outages in the Near-Term Transmission Planning Horizon that are expected to result in Non-Consequential Load Loss following a Table 1 P1 Event. It is noted that the performance requirements for all Table 1 Events include that the System shall remain stable, as well as Cascading and uncontrolled islanding shall not occur. Requirement R1 Part 1.1.2.2 Planned outages lasting less than six months could be overlooked when the Transmission Planner and Planning Coordinator formulate System models (FERC Order 786, Paragraph 42). Further, there is no correlation between the System impact of an outage and its duration. Therefore, while duration is an

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		acceptable factor to consider when selecting a known outage for representation in System models, the duration shall not be the sole factor for omission. <u>Requirement R1 Part 1.1.2.3</u> A technical rationale is necessary to establish a rules-based approach to the selection of known outages for representation in System models. Similarly, regional operational approaches and outage coordination procedures vary, but the selection of known outages should incorporate input from operational experience. Therefore, known outages shall be selected according to an established procedure or a technical rationale.
TPL-001-4, Requirement R2	TPL-001-5, Requirement R2	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	
TPL-001-4, Requirement R2 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.	TPL-001-5, Requirement R2 2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.	Requirement R2 Part 2.1.3 A properly planned Transmission system should facilitate maintenance outages without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
TPL-001-4, Requirement R2 2.4.3. 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.	TPL-001-4, Requirement R2 2.4.4~~3~~. 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.	<u>TPL-001-5, Requirement R2, Part 2.4.4</u> TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	
	TPL-001-5, Requirement R2 2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.	TPL-001-5, Requirement R2, Part 2.4.3 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.3. For reasons similar to those justifying changes to Requirement R2 Part 2.1.3, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of

Standard: TPL-001-5		
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		the BES to be assessed for System models that include known outages pursuant to Requirement R1 Part 1.1.2.
	TPL-001-5, Requirement R2 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.	TPL-001-5, Requirement R2, Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.
TPL-001-4, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for	TPL-001-5, Requirement R3 **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	No Modification Made

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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:	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

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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	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. 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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	mitigate the consequences and adverse impacts of the event(s) shall be conducted.	

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included in the Contingency list. 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.		
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R4 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.	TPL-001-5, Requirement R4, **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	<u>TPL-001-5, Requirement R4, Part 4.2</u> Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.

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	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. If the analysis concludes there	

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	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. ~~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~~	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~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:	

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	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	

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	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.~~	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

February 2018

RELIABILITY | ACCOUNTABILITY




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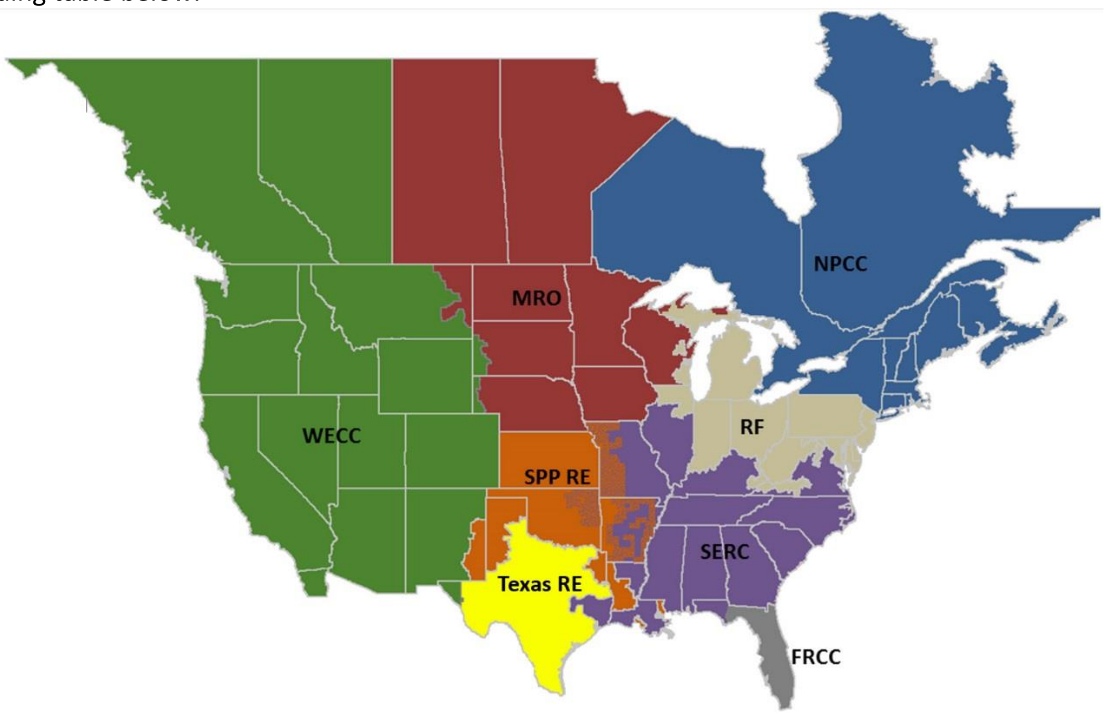
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standards Development Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Proposed revisions to "Table 1 – Steady State and Stability Performance Planning Events", adds a new P8 Planning Event to include a 3-phase fault and failure of a non-redundant component of a Protection System. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 and the proposed new Category P8 Planning Events.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, Category P3 and P6 do not sufficiently cover planned maintenance outages, and Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration and replace it with the requirement to document an established procedure or the technical rationale, to determine which known outages to study.. Proposed revisions includes stability study for long lead equipment that does not have a spare.

Summary of proposed revisions:

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Modified how known outages are selected for study.
- Requirement R2, Part 2.1.3 – Added model conditions for steady state analysis of P1 events for known outages.
- Requirement R2, Part 2.4.3 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Note the Steady State and Stability performance thresholds that are applicable to Category P1 through P7 events only and not to P8 events

- Table 1 – Added Category P8 event to include SPF following a 3-phase fault, with applicable performance thresholds
- Table 1 – Modified Footnote 13 to specify SPF.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with single points of failure (SPF) in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF. Available

FERC Order No. 786

In Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order 786. The white paper provides extensive general discussion regarding the directives.

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1 Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

2 Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the Technical Conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC PC/OC, summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action. To address this risk, the SPCS and the SAMS

[3] *See* *Industry Advisory: Single Point of Failure*
http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf

considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 standard drafting team are summarized in the following section.

Revisions to TPL-001-4

Table 1-Footnote 13

The SPCS/SAMS report recommended replacing “relay” with “component of a Protection System” in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of ’Protection System‘ for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Based on discussion and industry comment, the SDT proposes similar revisions to Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the drafting team sought to limit the scope of Footnote 13, item 1 with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. An SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the drafting team did not include backup protective relays in the scope of Footnote 13, item 1 given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The drafting team recognizes that Bulk Electric System (BES) Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault, and P8 event, for a 3-phase fault, in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as P5 and P8 events.

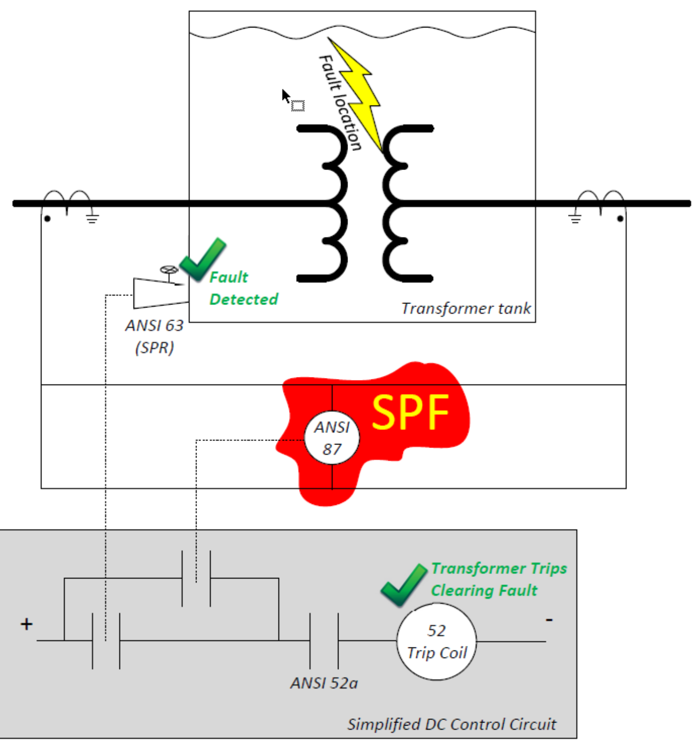

Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

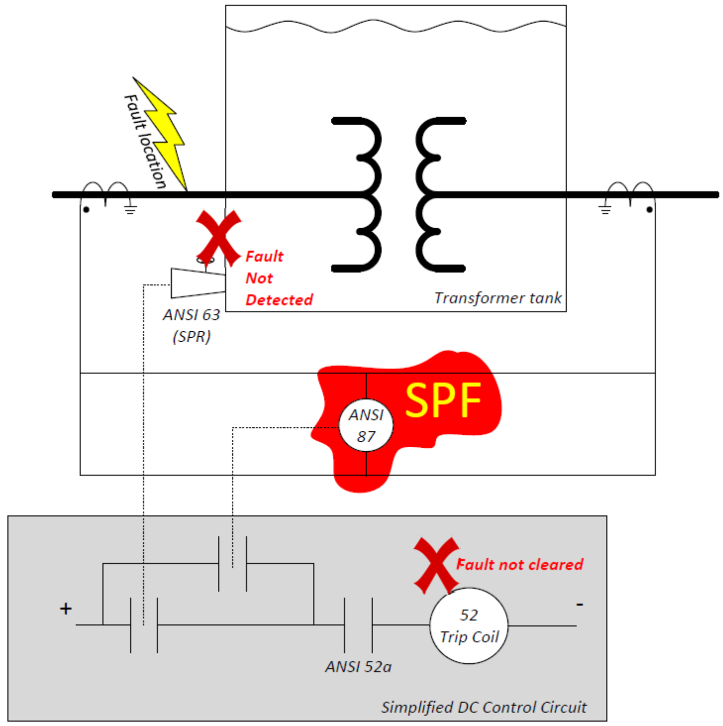

Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the Bulk Electric System can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

The drafting team adopted the fundamental principles of the SAMS/SPCS recommendations regarding station protection system DC supply. Failure of a single station protection system DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The drafting team partly modified the SAMS/SPCS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13, item c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit Therefore, this requirement may be more applicable to legacy systems.

The Distinction Between Category P4 and Category P5/P8 Planning Events

"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 and P8 Planning Events. The sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 and P8 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed Clearing associated with circuit breaker failure.

Single Points of Failure – Category P5 and P8 Planning Events

Analysis of the data collected under the Order No. 754 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant action. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to unacceptable system performance if a Protection System component SPF exists).

The drafting team has modified Table 1, Footnote 13 to capture the SAMS/SPCS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified single points of failure of concern.

Proposed revisions to "Table 1 – Steady State and Stability Performance Planning Events", adds a new P8 Planning Event to include a 3-phase fault and failure of a non-redundant component of a Protection System. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 and the proposed new Category P8 Planning Events

Given the risk to BES reliability raised at the FERC Technical Conference in conjunction with the SAMS/SPCS recommendations, the drafting team considered the manner in which additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. While events initiated by a three-phase fault are less probable than events initiated by a single-phase-to-ground faults, single-phase-to-ground faults with Delayed Clearing, particularly associated with the non-redundant components of a Protection System enumerated in Table 1, Footnote 13, can often evolve into three-phase faults, leading to system performance which is more severe than for the Table 1, P5 event. To address this concern (the study of Protection System SPF with a three-phase fault), the drafting team has developed a new P8 Planning Event; however, unlike the Category P1-P7 Planning Events, a Corrective Action Plan is only required if the P8 event results in Cascading. Accepting more severe system performance is seen as a reasonable balance with the lower likelihood, but reasonable risk, of the SPF with a three-phase fault. Table 1, Footnote 13 also provides the attributes of the specific non-redundant Protection System components that the entity shall consider for evaluation for the P5 and P8 events.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 and P8 Planning Events will likely be to add Protection System component redundancy, consistent with the components enumerated in Footnote 13. Protection System redundancy changes to address P5 concerns should also reduce or even negate non-redundant components that need to be considered in P8 events; hence, potentially mitigating many P8 concerns.

The P5 event steady-state analysis should also be valid and representative of P8 events. It should be noted that the addition of the P8 event will only add the need for additional stability analysis.

Requirement R4 Parts 4.2 and 4.5

The drafting team proposes non-substantive editorial changes to combine part of Requirement R4, Part 4.5 with Requirement R4, Part 4.2. The rearrangement of Requirement 4, Parts 4.2 and 4.5 were done to improve consistency within the Standard and do not create any new requirements. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable low-cost, cost-effective measures to lessen the risk or severity of these events.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing "with duration of at least six months" and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an "academic exercise" due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

Revisions to TPL-001-4

Requirement R1 Part 1.1.2

The drafting team gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the TP or PC.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective "one size fits all" means of addressing the FERC directive. However, FERC's Order 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available.

The drafting team modified Requirement R1, Part 1.1.2 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that TPs and PCs currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be studied.

It is only necessary to consider known outages expected to result in Non-Consequential Load Loss for P1 event in Table 1. This allows the PC and TP to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary modeling of outages which the PC and TP do not expect to be a problem.

Consistent with the intention of Order No. 786, the drafting team included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be modeled.

The PC and TP must have documented either an established procedure or technical rationale for the determination of which known outages may be excluded from modeling. The established procedure is intended to include consultation with the affected Reliability Coordinator, consultation with outage Transmission and/or Generator Owner(s), or application of established outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination.

This proposed modification is for consideration of known outages beyond the Operations Planning time horizon.

Requirements R2 Part 2.1.3 and Part 2.4.3

Consistent with FERC's directive, the drafting team modified Requirements **R2 Parts** 2.1.3 and 2.4.3 to further recognize the intent to limit required study to only those known outages that are expected to produce severe System impacts on the PC/TP's respective portion of the BES.

Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.

- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2 Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 standard drafting team revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning and protection engineers that will need to conduct the studies and submit the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines.

Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant Protection System component could result in a potential reliability risk. These entities must provide this information, as well as resulting fault clearing times, to Transmission Planners for proper study.

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Current Option (Draft 3):

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known -outage(s) of generation or Transmission Facility(ies) scheduled in ~~as selected in consultation with the Reliability Coordinator for~~ the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. ~~for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3~~Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

~~1.1.2.~~**1.1.3.** New planned Facilities and changes to existing Facilities.

~~1.1.3.~~**1.1.4.** Real and reactive Load forecasts.

~~1.1.4.~~**1.1.5.** Known commitments for Firm Transmission Service and Interchange.

~~1.1.5.~~**1.1.6.** Resources (supply or demand side) required for Load.

Option considered for Draft 3:

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. ~~These~~ This outage coordination~~s~~ ~~are~~ is required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Previous Option (Draft 2)

1.1.2 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.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The SDT did not feel like a time duration alone would capture "significant outages". Additionally, the language allows PC's to develop a process for selecting "significant outages" to be studied in the Near-Term Transmission Planning Horizon.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure13" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure13" with "a component failure of a Protection System13."
- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Revision By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and

- Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.

- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
    - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
    - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language.

Current Option Footnote 13 (Draft 3)

1. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    - A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times~~, e.g. sudden pressure relaying~~;
    - 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 at a Control Center;
    - A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for both low voltage and open circuit;
    - A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing.

Previous Option Footnote 13 (Draft 2)

The previous option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. 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;

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

c. 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;

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

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team added clarifications to the previous draft option which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

Extreme Events and P8 Category:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754, Section 1600 data collection and report indicated a risk to the BES for three phase faults followed by single points of failure of a protection system. Therefore, the SDT decided to make Category P8 planning event if a three-phase fault following by a single points of failure resulted in Cascading or instability.

Revision By Standard Drafting Team to Satisfy FERC Order

Current Option (Draft 3):

~~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. 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.

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 implementationList System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~

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

Previous Option (Draft 2):

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

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

Standard Drafting Team Proposal

The standard drafting team feels that there is a reliability risk to the BES if Cascading or instability results in a three-phase fault followed by single point of failure of a protection system. There was confusion in the industry with the language that was similar to a CAP but not exactly a CAP. Therefore, the standard drafting team decided to create a P8 planning event which required a CAP if Cascading or instability occurs.

Standards Announcement

Reminder

Project 2015-10 Single Points of Failure

Ballots and Non-binding Poll Open through April 23, 2018

Now Available

An additional ballot for **TPL-001-5 – Transmission System Planning Performance Requirements,** an initial ballot for the implementation plan**,** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, April 23, 2018.**

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience difficulties navigating the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

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Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Open through April 9, 2018

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Monday, April 9, 2018.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
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Next Steps

An additional ballot for the standard, an initial ballot for the implementation plan, and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted **March 30 – April 9, 2018.** The existing TPL-001-5 ballot pool was used for the initial ballot of the implementation plan.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/129)
Ballot Name: 2015-10 Single Points of Failure TPL-001-5 AB 2 ST
Voting Start Date: 4/13/2018 12:01:00 AM
Voting End Date: 4/23/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 236
Total Ballot Pool: 294
Quorum: 80.27
Weighted Segment Value: 26.44

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	16	0.267	44	0.733	1	2	16
Segment: 2	8	0.6	1	0.1	5	0.5	0	0	2
Segment: 3	67	1	12	0.218	43	0.782	0	1	11
Segment: 4	16	1	2	0.154	11	0.846	0	0	3
Segment: 5	65	1	11	0.234	36	0.766	0	2	16
Segment: 6	49	1	7	0.167	35	0.833	0	1	6
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.4	3	0.3	1	0.1	0	0	2
Totals:	294	6.2	54	1.639	175	4.561	1	6	58

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		Negative	Comments Submitted
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Negative	No Comment Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Devin Elverdi		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Eversource Energy	Quintin Lee		None	N/A
1	Exelon	Chris Scanlon		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Negative	Third-Party Comments
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Negative	Comments Submitted
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Third-Party Comments
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Third-Party Comments
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Negative	Comments Submitted
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Aaron Austin		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Vivian Vo		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Negative	Third-Party Comments
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Exelon	John Bee		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Third-Party Comments
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Negative	Comments Submitted
3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Third-Party Comments
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Fred Frederick		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Negative	Third-Party Comments
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Third-Party Comments
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Entergy	Jamie Prater		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Exelon	Ruth Miller		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Donald Sievertson		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Jonathan Aragon		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Franklin Lu		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Brenda Hampton		None	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Previous 1 Next

Showing 1 to 294 of 294 entries

BALLOT RESULTS

Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Non-binding Poll AB 2 NB
Voting Start Date: 4/13/2018 12:01:00 AM
Voting End Date: 4/23/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 209
Total Ballot Pool: 274
Quorum: 76.28
Weighted Segment Value: 27.01

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	14	0.326	29	0.674	11	17
Segment: 2	7	0.2	1	0.1	1	0.1	2	3
Segment: 3	63	1	10	0.238	32	0.762	8	13
Segment: 4	15	1	2	0.182	9	0.818	1	3
Segment: 5	61	1	8	0.216	29	0.784	8	16
Segment: 6	47	1	7	0.212	26	0.788	5	9
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	6	0.4	3	0.3	1	0.1	0	2

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Totals:	274	5.8	47	1.774	127	4.026	35	65

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Devin Elverdi		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A
1	Exelon	Chris Scanlon		None	N/A
1	Georgia Transmission Corporation	Greg Davis		Negative	Comments Submitted
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Negative	Comments Submitted
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	LS Power Transmission, LLC	John Seelke		None	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Comments Submitted
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		None	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	Westar Energy	Kevin Giles		Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	California ISO	Richard Vine		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Aaron Austin		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		Negative	Comments Submitted
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
3	Georgia System Operations Corporation	Scott McGough		Negative	Comments Submitted
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	JEA	Garry Baker		None	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Negative	Comments Submitted
3	Portland General Electric Co.	Angela Gaines		None	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Comments Submitted
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Mark Oens		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Negative	Comments Submitted
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Negative	Comments Submitted
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Negative	Comments Submitted
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Comments Submitted
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Comments Submitted
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Comments Submitted
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Comments Submitted
5	Puget Sound Energy, Inc.	Eleanor Ewry		None	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		Negative	Comments Submitted
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		None	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	Comments Submitted
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		None	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		Negative	Comments Submitted
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Franklin Lu		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Brenda Hampton		None	N/A
8	David Kiguel	David Kiguel		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Showing 1 to 274 of 274 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/129)
Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Implementation Plan IN 1 ST
Voting Start Date: 4/13/2018 12:01:00 AM
Voting End Date: 4/23/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 230
Total Ballot Pool: 294
Quorum: 78.23
Weighted Segment Value: 41.13

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	23	0.418	32	0.582	0	7	17
Segment: 2	8	0.3	3	0.3	0	0	0	2	3
Segment: 3	67	1	18	0.34	35	0.66	0	3	11
Segment: 4	16	1	3	0.231	10	0.769	0	0	3
Segment: 5	65	1	15	0.341	29	0.659	0	4	17
Segment: 6	49	1	11	0.297	26	0.703	0	3	9
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.4	3	0.3	1	0.1	0	0	2
Totals:	294	5.9	78	2.427	133	3.473	0	19	64

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Wes Wingen		Abstain	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Third-Party Comments
1	Colorado Springs Utilities	Devin Elverdi		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		None	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Negative	Comments Submitted
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		None	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Karen Yoder		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh	Oshani Pathirane	Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		Negative	Comments Submitted
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	LS Power Transmission, LLC	John Seelke		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	MEAG Power	David Weekley	Scott Miller	Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Abstain	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Long Duong		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Negative	Comments Submitted
1	Salt River Project	Steven Cobb		Negative	Comments Submitted
1	Santee Cooper	Shawn Abrams		Negative	Comments Submitted
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Negative	Comments Submitted
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Negative	Comments Submitted
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		None	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Unisource - Tucson Electric Power Co.	John Tolo		None	N/A
1	Westar Energy	Kevin Giles		Negative	Third-Party Comments
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	Third-Party Comments
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	None	N/A
2	Midcontinent ISO, Inc.	Ellen Oswald		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		None	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Aaron Austin		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		None	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		None	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Negative	Third-Party Comments
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		Affirmative	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	JEA	Garry Baker		None	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Negative	Comments Submitted
3	Modesto Irrigation District	Roderick Cook	Nick Braden	None	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Randy Hahn	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Negative	Comments Submitted
3	Portland General Electric Co.	Angela Gaines		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	PSEG - Public Service Electric and Gas Co.	Jeffrey Mueller		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Negative	Third-Party Comments
3	Salt River Project	Robert Kondziolka		Negative	Comments Submitted
3	Santee Cooper	James Poston		Negative	Comments Submitted
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	James Frauen		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Snohomish County PUD No. 1	Mark Oens		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		None	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bo Jones		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Michael Ibold		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Negative	Third-Party Comments
4	City of Clewiston	Lynne Mila	Brandon McCormick	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		Negative	Comments Submitted
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Guy Andrews		Affirmative	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Negative	Comments Submitted
4	Seattle City Light	Hao Li		Negative	Comments Submitted
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		None	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Negative	Third-Party Comments
5	City of Independence, Power and Light Department	Jim Nail		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Third-Party Comments
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		Negative	Third-Party Comments
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Donald Sievertson		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Negative	Comments Submitted
5	Manitoba Hydro	Yuguang Xiao		Negative	Comments Submitted
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		None	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		Affirmative	N/A
5	OTP - Otter Tail Power Company	Cathy Fogale		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Comments Submitted
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Negative	Comments Submitted
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Negative	Third-Party Comments
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Negative	Comments Submitted
5	Salt River Project	Kevin Nielsen		None	N/A
5	Santee Cooper	Tommy Curtis		Negative	Comments Submitted
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		None	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Laura Cox		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Abstain	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Third-Party Comments
6	Colorado Springs Utilities	Shannon Fair		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Robert Winston		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Negative	Comments Submitted
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Luminant - Luminant Energy	Kris Butler		None	N/A
6	Manitoba Hydro	Blair Mukanik		None	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	None	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		None	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Negative	Comments Submitted
6	Salt River Project	Bobby Olsen		None	N/A
6	Santee Cooper	Michael Brown		Negative	Comments Submitted
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		None	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Negative	Comments Submitted
6	Snohomish County PUD No. 1	Franklin Lu		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Negative	Comments Submitted
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Megan Wagner		Negative	Third-Party Comments
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Third-Party Comments
7	Luminant Mining Company LLC	Brenda Hampton		None	N/A
8	David Kiguel	David Kiguel		None	N/A
8	Massachusetts Attorney General	Frederick Plett		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		None	N/A
10	Midwest Reliability Organization	Russel Mountjoy		None	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted

Showing 1 to 294 of 294 entries

Previous 1 Next

Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Open through April 9, 2018

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Monday, April 9, 2018.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for the standard, an initial ballot for the implementation plan, and a non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted **March 30 – April 9, 2018.** The existing TPL-001-5 ballot pool was used for the initial ballot of the implementation plan.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5
Comment Period Start Date:	2/26/2018
Comment Period End Date:	4/23/2018
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 AB 2 ST 2015-10 Single Points of Failure TPL-001-5 Implementation Plan IN 1 ST

There were 70 sets of responses, including comments from approximately 190 different people from approximately 117 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the creation of the proposed P8 event?

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

3. Do you agree with the proposed implementation plan?

4. Do you agree with the proposed revisions to TPL-001-4?

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Paul Henderson	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF

					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC

					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Haley Sousa	5		Chelan PUD	Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
DTE Energy - Detroit Edison Company	Jeffrey DePriest	3,4,5		DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
JEA	Joe McClung	3,5	FRCC	JEA Voters	Ted Hobson	JEA	1	FRCC
					Garry Baker	JEA	3	FRCC
					John Babik	JEA	5	FRCC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC

Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC
					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Hydro One, NYISO and Eversource	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC

Randy MacDonald	New Brunswick Power	2	NPCC
Wayne Sipperly	New York Power Authority	4	NPCC
Glen Smith	Entergy Services	4	NPCC
Brian Robinson	Utility Services	5	NPCC
Bruce Metruck	New York Power Authority	6	NPCC
Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated	3	NPCC

						Edison Co. of New York		
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO

Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Amy Casuscelli	Xcel Energy	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Kiet Nguyen	Grand River Damn Authority	1	SPP RE
					louis Guidry	Cleco	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma Gas and Electric Co.	6	SPP RE
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	SPP RE
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	SPP RE

					John Rhea	OGE Energy - Oklahoma Gas and Electric Co.	5	SPP RE

1. Do you agree with the creation of the proposed P8 event?

Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	

Comment

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called “Joint Report”).

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events ‘to a planning event with its own system performance criteria’ (Joint Report, **Chapter 2 – Alternatives**, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that “**Probability of three phase fault with a protection system failure is low enough that it does not warrant a planning event**”. The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is “the existence of a reliability risk associated with the single points of failure in protection system that warrants further action” (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, **Chapter 3 – Conclusion**, pg 11). Accordingly, the SAR has defined the scope of the SDT’s work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the “analysis indicates an inability of the System to meet the performance requirements in Table 1” which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission’s concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 1	JEA, 5, Babik John
Dislikes 0	

Response

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6

Answer	No
Document Name	

Comment

NextEra does not support P8 events being considered as planning events instead of extreme events. A 3PH fault plus protection system failure is a very low probability event.Ne

Likes 0	
Dislikes 0	

Response
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment
For the HV BES level, both Categories P5 and the new P8 events require the same performance for both a SLG fault and a 3-Phase fault. BPA believes the performance for the existing P5 is more conservative and the P8 Category is not required for the HV BES level. In addition, BPA suggests deleting the new P8 and modifying P5 to include a row for 3Ø (three phase) for the EHV BES level only allowing interruption of firm transmission service and non-consequential load loss.

Likes 0	
Dislikes 0	

Response
Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment
Adding P8 changes a an EXTREME contingency to a CREDABLE contingency. A 3 phase fault with delayed clearing was an extreme event under category D on Table 1 of the original TPL standards. This contingency has always been an extreme contingency. The question not being addressed is, “what reliability improvement can be accomplished by adding P8?”. If P8 studies show instability, there is no requirement for a corrective action plan. Keeping in mind that this is a required standard, why create a P8 contingency, which will increase the work load and cause additional distractions, when the results don’t matter?

Likes 0	
Dislikes 0	

Response
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Seminole is in agreement with the comments submitted by JEA but would like to provide additional comments relating to the proposed P8 Event. In reviewing the Cost Effectiveness document, the Technical Rationale, the SPCS/SAMS Order 754 Report, and the proposed redline to the existing TPL-001 Reliability Standard, Seminole does not believe that the proposed P8 Planning Event is prudent and the technical rationale is flawed in light of what the SPCS/SAMS documented in their review of the Order 754 Data Request analysis. As documented by JEA, the SPCS/SAMS never recommended making a three-phase fault with a single point of failure a Planning Event unless it included its own performance criteria. Additionally, the SDT and the SPCS/SAMS clearly recognize that a three-phase fault is in and of itself an event that has a low probability of occurrence, and adding a low probabilistic single point of failure of a protection system on top and requiring that this be analyzed as a Planning Event is beyond prudent planning and results in diminishing returns from an analysis and cost effectiveness standpoint. The SDT also made a gross assumption in regards to the amount of work required to evaluate these events by stating that the P8 Planning Event does not require steady state evaluation and “ONLY” requires stability analysis as to insinuate that the level of work is somehow lessened by making this statement.

The cost effectiveness document falls short of providing any substantive cost effectiveness in regards to the additional analysis that would be required by the addition of Planning Event P8

Suggestion:

The existing Extreme Event within Table 1, 2f., allows for the Transmission Planner to use operating experience to develop a contingency event that would result in a wide-area disturbance, such a disturbance that one could presume would cause Cascading, voltage instability or uncontrolled islanding. Operating experience would bring one to the conclusion that the proposed P8 Planning Event is in fact a low probabilistic event and should NOT be considered a Planning Event but rather an Extreme event that is already part of the Extreme Event Table within Table 1

Likes 0	
Dislikes 0	

Response

Jeff Landis - Platte River Power Authority - 3

Answer	No
Document Name	

Comment

PRPA supports JEA comments.

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called “Joint Report”).

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events ‘to a planning event with its own system performance criteria’ (Joint Report, Chapter 2 – Alternatives, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that “Probability of three phase fault with a pro low enough that it does not warrant a planning event”. The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is “the existence of a reliability risk associated with the single points of failure in protection system that warrants further action” (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, Chapter 3 – Conclusion, pg 11). Accordingly, the SAR has defined the scope of the SDT’s work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the “analysis indicates an inability of the System to meet the performance requirements in Table 1” which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from

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draft 2) and the clarified Footnote 13 will adequately address the Commission’s concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP does not agree with the creation and inclusion of P8 for the following reasons:

1. We see nothing within the project’s final SAR which would accommodate the addition of a completely new Performance Planning Event in Table 1. As a result, we believe its proposed inclusion goes beyond the scope of the SAR.

2. The creation of P8 introduces an inconsistent treatment of breaker failure. A 3-phase fault with the failure of a non-redundant component of a Protection System (footnote 13.d, such as the failure of single-control circuitry that would prevent tripping but initiate breaker failure) that results in a breaker failure operation is considered a Planning Event in P8. However, the same 3-Phase fault with a stuck breaker is included under Extreme events in the Stability column and results *in the exact same event*. If a 3-phase fault results in a breaker failure operation, what is the reliability benefit of differentiating the cause between a Protection System component failure or a stuck breaker? While AEP disagrees with many aspects of the recently-proposed revisions, the concerns expressed in this paragraph are the primary drivers behind our decision to vote negative during this comment/ballot period.

3. AEP is concerned that the inclusion of P8, coupled with its indistinct relationship to P5, will lead to inconsistent decision-making when using and applying Table 1. This was well illustrated during the March 22nd webinar by both the questions posed and the responses and insight provided by Chris Colson. A number of possible scenarios were provided by remote attendees seeking insight how the table should be correctly applied in those cases. At

times, Mr. Colson expressed appreciation for the thought process, reasoning, and “logical analysis” used by those who were posing the questions and referencing Table 1. Our own impressive was different however, as we believe referencing the Table in such a “nonlinear” or “cyclical” way would actually lead to inconstant interpretation and application of the table. As a result, we believe it is possible (and perhaps even likely) that the table will not be consistently applied.

In our response to Question #4, AEP has provided possible alternatives to P8's inclusion for the drafting team to consider.

Likes 0	
Dislikes 0	

Response

Shawn Abrams - Santee Cooper - 1

Answer	No
Document Name	

Comment

Santee Cooper supports JEA’s comments on this standard. No, the addition of the P8 event in Table 1 goes beyond what is required by the SAR. The Joint Report cited that the probability of a three-phase fault with protection system failure is low enough that it does not warrant a planning event. The creation of the P8 event is not warranted and should be removed.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14

will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
I support comments submitted by the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

NIPSCO agrees with JEA's comments.

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called "Joint Report").

*However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, **Chapter 2 – Alternatives**, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "**Probability of three** **-ph** **that it does not warrant a planning event**". The creation of the proposed P8 event in this version has clearly overlooked this fact.*

*The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, **Chapter 3 – Conclusion**, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes* *outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.*

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

***Suggestion**: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the* Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

See JEAs response.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No
Document Name	

Comment

OG&E considers the proposal to categorize the P8 event as a Planning Event as being in conflict with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its "Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" white paper ("Joint Report"). The SPCS and SAMS advised that three-phase fault Single Point of Failure events should remain categorized as Extreme Events and that "[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event." *See* Order 754 Assessment at pp. 9 and 11.

Recommendation: Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should

not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
The roposed addition of the P8 in Table 1 is beyond the standard requirements. the possiblity of this event occuring is very remote. Requirement R4.3 (the deleted portion) should be kept in the standard. The proposed changes does not address any current issues or concerns based on the past history. the changes on the remedia; actopm scheme seems to be appropriate.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Given the similarities between P5 and P8 events, NVE recommends that the proposed P8 events should replace the existing P5 events. It is expected that in most portions of the BES, there will be few, or no, SLG contingencies that would result in more severe impacts than the corresponding 3 phase fault contingencies with a failed non-redudant component of a Protection System. A Footnote 14 can be added to the Fault Type that allows the Transmission Planner or Planning Coordinator to change the fault type from 3 Phase to L-G based on the failure of the non-redundant component of a Protection System being studied (i.e. a SLG fault for a failure of a single phase electromechanical relay) or based on the impact to the system.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

P5 events already covers the concern of failure of non-redundant protection systems with a single line to ground fault. The majority of multiple contingency events in TPL-001 only require analysis of a more frequent single line to ground fault. By including the P8 event, development of a corrective action plan may be required for a very low probability event (3-phase fault plus failure of a protection system). Ideally the drafting team should attempt to calculate probabilities and keep the single and multiple contingency categories within roughly a one in thirty year probability of occurring. All other less frequent events should be considered extreme and it should be up to the discretion of the Transmission Planner/Planning Coordinator whether investment is warranted.

If 3-phase faults are assumed to have a 1 in 10 year frequency and protection failure a 1 in 10 year frequency then a 3 –phase fault with protection failure has a 1 in 100 year frequency. Single phase faults have a higher probability of 1 in 1 year to 1 in 3 year depending on the voltage level. Protection failure with a single phase fault is closer to 1 in 30 years.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	No
Document Name	

Comment

By creating the new “P8” single-point-of-failure category of events and by requiring a Corrective Action Plan (CAP) when such P8 events cause cascading or uncontrolled islanding, the Standard Drafting Team has clearly gone beyond the recommendation in the Standard Authorization Request (SAR). The SAR only recommends that the TPL-001-4 standard be revised “so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection system.” It does not recommend or require that these new P8 events, which are extreme events, be held to a higher standard than thaFlppst of the other extreme events with a new event category unto itself. It also does not recommend or require that such events be mitigated with a CAP, a requirement that is not applied to any of the other extreme events. These P8 events are extreme events and should be held to the same criteria that is applied to the other extreme events.

SMUD supports the SAR recommendation to include single-point-of-failure events in its annual assessment of extreme events. SMUD does not, however, support the hard requirement to mitigate such events when studies indicate they may lead to cascading or uncontrolled islanding and prefers instead to leave the decision to mitigate such events to the Planning Coordinator and Transmission Planner just as such discretion exists for all other extreme events.

However, by including the P8 event in Table 1, it inappropriately and erroneously subjects the category P8, extreme events, to Requirement 2.7 that requires a CAP when performance requirements are not met, effectively exceeding the concepts included in the SAR.

The P8 events is an extreme event and needs to be held to the same requirements as applied to other extreme events.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

Likes 0	

Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy disagrees with the creation of the proposed P8 as a Planning Event. The proposed addition of the P8 event goes beyond of what is required in the Standards Authorization Request (SAR). The joint report by the SPCS and SAMS subcommittees considered the events (similar to the proposed P8) to be ‘elevated to a planning event with its own system performance criteria’ (Chapter 2 – Alternatives of the Joint-report) as one of the alternatives, however, the joint report did NOT recommend this alternative citing the fact that “Probability of three protection system operate fault with a failure is low enough that it does not warrant a planning event”.

The probability of this event occurring is low, and the change of “relay” to “components of a Protection System” with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint-report.

The implementation of the proposed P8 event is NOT needed and should be removed. We believe that Requirement 4 sub-requirement 4.2 together with clarified P5 (Table 1), modified extreme events – stability 2e-2h (Table 1), and the clarified Footnote 13 will adequately address the Commission’s concerns.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	No
Document Name	
Comment	

Neither the SAR, FERC Orders, or the SPCS/SAMS report appear to require or explicitly recommend the creation of a new planning event type in order to address single-point-of failure. Based on the data reported in NERC’s analysis of the Order 754 Data Request, the conclusion can be drawn that the majority of scenarios which will need to be analyzed under the P8 event will consist of lower voltage facilities which are less likely to create an “adverse system impact” as compared to higher voltage facilities that are more likely to have fully redundant protection systems. Such events are already included under the existing category of “extreme events” – a more efficient way to address the risks of critical SPF scenarios (as well as other critical vulnerabilities that might exist) might be to direct the TP or PC to develop a more defined process to screen extreme events, identify those which pose the greatest risk, and to determine those that may be appropriate to study and possibly mitigate.

Likes 0	
Dislikes 0	

Response	
John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
See Exelon TO Utilities Comments	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	FMPA_2015-10_Unofficial_Comment_Form_2018423_2_.docx
Comment	

FMPA disagrees for the following reasons.

1. The revisions exceed the properly and dutifully developed scope of the SAR, and do so without any substantiated basis (e.g. there is no “new evidence” to suggest the scope of the SAR should have been exceeded). Creating a Planning level event was a specific option considered by the NERC System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling subcommittee (SAMS) in their joint report, referenced in the Technical Rationale for this Project. The purpose of the SAMS/SPCS joint report was to evaluate the available data and make a recommendation as to the level of reliability risk that did, or did not, exist, and recommend paths forward to address those risks. Industry provided the data for the Section 1600 data request dutifully and faithfully entrusting SPCS and SAMS to carefully anyalze that data and make reasonable recommendations to industry, NERC and FERC based on the evidence. This is what SPCS and SAMS did. The joint report concluded a Planning level event was not warranted and made recommendations to ensure that Protection system failures with three phase faults were studied as extreme events.

2. Elevating an event to a Planning event when data does not suggest this is warranted creates complexity and confusion and puts other events at risk of the same fate and changes aspects of the planning standard that were working well and did not need to be changed. The joint report concluded there was a reliability risk. FMPA agrees with this. The joint report recommended modifying the extreme events and footnote 13 in the TPL-001-4 standard. Again, FMPA agrees with this approach – it makes sense given the data that industry provided in the Section 1600 data request. Effectively, a protection system failure with a three phase fault represents the same reliability risk as a breaker failure event with a three phase fault, which is already studied as an extreme event. This grouping was already contemplated in the prior revision of TPL-001-4; it was the over-simplification of the description of protection systems in the footnotes and lack of explicit statements in the extreme events list in Table 1 that created the reliability gap. The end result

of creating a Planning level event for Protection System failures would be to send the message that the other three phase fault extreme events which are statistically equivalent to them should also be studied as planning events.

3. FMPA disagrees with the Technical Rationale on three points and therefore does not agree that introduction of this P8 event is justified or warranted:

A. The Technical Rationale for this Project makes the argument that the reason a Planning Event is warranted is the mere fact that the joint report exists – a report which concluded the exact opposite. This makes no sense, and serves to undermine all the work industry, SPCS, and SAMS did in investigating the reliability risks and determining a path forward to address those risks.

B. The Technical Rationale's assertion that elevating protection system failures to a Planning Event is not significant since CAPs are only required if there is a risk of Cascading or or widespread electric service disruption doesn't make sense, since industry has previously, and through much development and debate, established the clear line that Planning events are based on more rigorous performance criteria than this. Hence, an event that is only required to be remedied if it causes Cascading or widespread electric service disruption (but not other performance criteria violations) is not a Planning Event and doing so only creates confusion in the standard where previously there was clarity.

C. FMPA also feels it is poor justification to claim that the prior round of industry comments requested the creation of this Planning event. The prior industry comments were solely a reaction to the confusion that was introduced into the standard when the SDT attempted to exceed the scope of the SAR by creating a quasi-third performance category. The result of this was industry felt forced to pick sides. FMPA does not believe any entity in industry, not one single commenter, would have recommended a Planning event if the original draft that was posted for comment had followed the scope of the SAR and left these events as extreme events where they belong.

FMPA would support doing what was recommended by the SPCS/SAMS joint report and what was written in the SAR for this project, and does not support exceeding the scope of the SAR nor the recommendation of the joint report, which this current proposition does. It is of the utmost importance that we send a message to industry that, when a 1600 data request is prepared and industry is asked to carefully analyze an issue, we will make use of that analysis and value it, and that when we request that changes to standards be based on careful, logical analysis, and that careful, logical analysis is completed, we follow the recommendations of that analysis.

To be very clear: FMPA believes protection system failures should be studied, and FMPA already studies protection system failures in a rigorous fashion.It is quite likely that, should FMPA identify performance issues due to protection system failures in its studies, FMPA and/or its members would upgrade its/their protection systems to address the observed issues. That is, good engineering and planning practices will be followed. However, FMPA believes that any system upgrades or CAPs that are mandated by the standard language should be based on reliability risks; and not just because they are "inexpensive or "easy".

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No
Document Name	

Comment

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

See comments from MRO NSRF.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski

Answer	No
Document Name	

Comment

GRE agrees with the MRO NSRF and ACES comments.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

Due to possible confusion with interpretation of the new P8 event, we do not fully agree with the implementation of the new event in the Standard.

The distinction and required performance criteria for the P5 and P8 events should be clarified and specifically documented within the Standard. As presented, Table 1 (Steady State & Stability Performance Planning Events) is difficult to interpret. One method to clarify the table might be to separate out the P8 event within Table 1 (Steady State & Stability Performance Planning Events) and specifically document the steady state and stability performance requirements for P8.

For example, it is not clear from the Standard if a Corrective Action Plan is only required if the P8 event results in Cascading.

One additional observation for Table 1 (Steady State & Stability Performance Planning Events). Per Table 1, steady state and stability analysis is applicable for the P5 event and the P8 event. The implementation of the P5 event and the P8 event in steady state analysis will likely be identical for both of these events (since fault type usually is not considered). However,

- for P5, Non-Consequential Load Loss is not allowed for EHV facilities.
- For P8, Non-Consequential Load Loss is allowed for EHV facilities.

This is a possible contradiction that should be reviewed and clarified.

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	

Comment

The proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, ***Chapter 2 – Alternatives***, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "***Probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event***". The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is *"the existence of a reliability risk associated with the single points of failure in protection system that warrants further action"* (We agree with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") does not agree with the creation of the proposed P8 event. A three-phase fault plus delayed fault clearing due to the failure of a non-redundant component of a Protection System in one event is a very rare occurrence in power system disturbances, beyond the scope of a planning event, and therefore should be considered an Extreme Event. As an alternative to the creation of a proposed P8 event, CenterPoint Energy recommends modifying the Extreme Event requirement, as proposed in the approved SAR, to expressly require evaluation of a three-phase fault and Protection System failure.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.

Likes 0	
Dislikes 0	

Response

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4

Answer	No
Document Name	

Comment

See comments below.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

We believe the proposed three-phase analysis is duplicative to Category P5 events that study single-phase-to-ground fault types. While three-phase faults can be more severe, the probability of such events are less likely to occur. This could set a precedence requiring PCs and TPs to include other less likely events in their future studies, or held accountable otherwise. We recommend removing this proposed event from the standard and provide registered entities an opportunity to individually address, on their own and not required through this standard, the concerns to BES reliability raised during the FERC Technical Conference, recommendations from various NERC Technical Subcommittees, and the efforts of this SDT.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment	
The SPP Standards Review Group considers the proposal to cateogorize the P8 event as a Planning Event as going beyond the scope of the Federal Energy Regulatory Commission's (FERC) Order No. 754. The FERC order requires that NERC review how single points of failure on protection systems are studied and identify additional actions necessary to address the matter; however, Order 754 does not require a Corrective Action Plan (CAP) to be developed or implemented. *See* Order No. 754 at PP 19-20. By re-categorizing P8 events as a Planning Event, rather than an Extreme Event, the proposed standard would require the TP to prepare a Corrective Action Plan in accordance with Section 2.7 *et seq.* of TPL-001-4. Summarily, the proposed revision presents a requirement not specifically defined by FERC. Moreover, the proposal to categorize P8 contigencies as Planning Events conflicts with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its Order No. 754 assessment (Joint Report). The SPCS and SAMS advised that P8 events should remain categorized as an Extreme Event and that "[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event." *See* Joint Report at 9 and 11. Recommendations: 1. Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concerns, recommendations from the Joint Report, and satisfy the objective of the SAR, regarding the single points of failure in Protection Systems. 2. Should the drafting team decide to categorize a P8 contingency as a Planning Event, the drafting team should consider expanding the applicability of the standard to include those functional entities from which the Transmission Planner (TP) must receive system protection data: Generator Owner (GO), Transmission Owner (TO), and Distribution Provider (DP). Because a non-vertically integrated Planning Cooridnator (PC) or TP (e.g., an RTO/ISO) must receive and coordinate system protection data from the GO, TO, and DP in order to satisfy the planning requirements, the standard should be revised to include data submission requirements for the GO ,TO, and DP. The proposed standard's reliance on MOD-032 as a means to receive system protection data is insufficient because MOD-032 does not specifically require such data be provided to the TP.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We support JEA comments	
Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
The focus of the contingencies must be on the likelihood of them happening. P8 contingencies consist of a three-phase fault plus non-redundant component of a protection system failure to operate. Oncor's transmission system experiences very low instances of three-phase faults as compared to single-phase faults. In addition, a three-phase fault with non-redundant component of a protection system failure to operate is even more rare. The likelihood or probability of a P8 contingency occurring is so low that Oncor believes it would not be practical both from an engineering and economical standpoint to elevate this event to a P level contingency. It better fits in the extreme event category.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
If the fix for a cascading three-phase fault with delayed clearing event is the installation of a redundant system protection component, we thoroughly support such a change.	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes

Document Name	

Comment

We agree with the creation of the proposed P8 event. However, in our view, following a P8 event the tripping of a circuit due to a generator pulling out of synchronism should be permissible as long as it doesn't result in cascading or uncontrolled separation. The proposed standard requires that for the P8 planning event, "The System Shall remain stable" and "Cascading and uncontrolled islanding shall not occur". However, since, there isn't a common understanding of what the system remaining stable means, we suggest including the following sub-requirement in the standard for additional clarity:

4.1.4. For planning events P8: When a generator pulls out of synchronism in the simulations, the resulting apparent impendace swings shall not result in Cascading.

Alternatively, a similar clarification as our proposed sub-requirement 4.1.4 can be added to Condition (a) on top of Table 1 as follows:

a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.

Likes 1	Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

SRP supports the addition of the P8 event. If the occurrence of a P8 event violates the performance requirements of Table 1, even after Interruption of Firm Transmission Service and Non-Consequential Load Loss, then corrective actions are warranted.

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	Yes
Document Name	

Comment

ITC agrees with the SDT that the creation of a P8 event is appropriate to build CAP to prevent the system from cascading when a SLG fault propagates into a 3-phase fault.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the creation of the proposed P8 event. Texas RE recommends including Item J in Table 1 in the Steady State & Stability (P0 through P8 events) list as stability issues can be associated with voltage.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Yes. We agree with adding the proposed P8 event with the understanding that Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, then if needed, the corresponding SLG fault contingency. More specifically, the need to simulate a subsequent SLG fault of the corresponding contingency would be only if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. It is also expected that there will be “extremely few,” or more likely “no”, SLG fault contingencies that would result in more severe impacts than the corresponding 3-phase fault contingencies. Please see comment for Footnote 14 in the responses to Question 4. It is difficult to ascertain the simulation performance requirement for P8 events. To help clarify these performance requirements for the proposed P8 events, suggest inserting R4.1.4 that reads: For planning event P8, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	

The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability, and islanding. This exceeds the SDT’s original intent to require development and implementation of a CAP to avoid Cascading only.

To remove the performance requirements for instability and islanding for a P8 event, ERCOT suggests the following wording changes to Condition (a):

(a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.

Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

CHPD appreciates the effort of the SDT to address the directives from FERC Order No. 786, and the recommendations in response to Order No. 754 from the SPCS and the SAMS regarding the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request ("Joint Report")).

Indeed, the primary goal of the Standards Authorization Request (SAR) is to implement the recommendations in the Joint Report. However, the Joint Report states that "***probability of three*** ***-phase fa*** ***event.***" As such, we believe that the proposed addition of the P8 planning event is overreaching and beyond the scope of the SAR.

The Joint Report does acknowledge *"the existence of a reliability risk associated with the single points of failure in protection system that warrants further action"* and therefore recommended additional emphasis in planning studies to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg. 11). Accordingly, the SAR defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event falls outside the scope of the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan (CAP) if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which includes the P8 event.

With the exception of the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address FERC's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	

Comment	
The creation of the proposed P8 event raises the following issues: The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability and islanding. This exceeds the SDT’s original intent to making a 3-phase fault with delayed clearing a planning event thus requiring the development and implementation of a CAP to avoid Cascading only. To remove the performance requirements for instability and islanding for a P8 event, we suggest the following wording changes to Condition (a): 1. For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
This change appears to require the creation of a model for every outage, without regard for the length of the outage. The requirement is already part of the performance standard through the application of P5 contingencies. The revision as proposed would require a proliferation of cases be developed and maintained and lead to confusion about which case to use. The development of cases for known outages seems appropriate for the operational time horizon but impracticle for the long-term planning time horizon. Reliability of the system during outages in the long-term planning horizon can be studied appropriately through the development of contingencies accompanied with appropriate generation adjustments to be applied to individual known outages within the seasonal period defined by a planning case as opposed to developing a seperate case for each combination of known outages. Further, the changes proposed under 2.1.3 create confusion around which P1 events need must be studied.	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
We need clarification. Oncor does not consider known outages to be a modeling issue. Including known outages with other contingencies appears to be more like a P6, two overlapping singles, than a modeling issue.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light would like further clarity of what is expected.	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and perform the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

Subpart 2.1.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.1.1 and 2.1.2***, when known outages are scheduled."

Subpart 2.4.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.4.1 and 2.4.2***, when known outages are scheduled."

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

We believe the proposed change should be simplified as a procedure or technical rationale that identifies what is a known outage should not be embedded within this requirement. The requirement focuses on maintaining system models, not developing procedures or technical rationales. These models must be based on data consistent with NERC Reliability Standard MOD-032-1, Corrective Action Plans, and other data sources. We recommend the SDT follow the acceptable approach suggested within the FERC directive that identifies significant planned outages can be based on registered entity-selected facility ratings or other parameters for inclusion within system models.

Likes 0	
Dislikes 0	

Response

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4

Answer	No
Document Name	

Comment

See comments below.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA supports AZPS's comments. The language is vague and could result in misinterpretation of the requirement. The wording "selected known outages" and "known outages" can cause confusion.

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy believes the language in Requirement R1.1.2 could lead to confusion as to which outages are required to be studied. FERC Order 786, paragraph 43 identifies "decreasing the outages to fewer months to include additional significant planned outages" as an acceptable approach. CenterPoint Energy recommends the SDT reconsider this approach and identify a 3-month threshold to capture the outages over which FERC was concerned.

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	

Comment

We agree with removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction.

The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific. Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard.

Therefore, we recommend that 1.1.2. be modified as follows:

1.1.2 Known Expected outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum:

1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans

1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage)

1.1.2.4 Does not exclude known transmission outage(s) soley based on the outage duration

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment	

We applaud removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction.

The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific.   Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard.

Therefore, we recommend that 1.1.2. be modified as follows:

1.1.2 **Expected** outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum:

1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans

1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage)

1.1.2.4 Does not exclude known **transmission** outage(s) soley based on the outage duration

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE appreciates the Standard Drafting Team's (SDT) continuing efforts to develop a workable definition to implement the Federal Energy Regulatory Commission (FERC) directive in FERC Order No. 786 to include planned maintenance outages of significant facilities in future TPL-001 planning assessments and eliminate the previous six-month bright line inclusion criterion. Texas RE particularly appreciates the SDT's reconsideration of developing a significant outage test based solely upon outages "selected in consultation with the Reliability Coordinator." However, Texas RE remains concerned that the current draft TPL-001-5 R1.1.2 language, if adopted, would be unworkable. Rather than the SDT's proposed approach, Texas RE instead recommends that the SDT require Transmission Planners (TP) and Planning Coordinators (PC) to identify and model known outages selected in accordance with an established procedure that (1) requires selection based on the MW or facility rating criteria identified by FERC in FERC Order No. 786; (2) provides a technical justification for the specific MW and facility rating threshold selected; and (3) does not exclude known outage(s) solely based upon the outage duration.

Texas RE's principal concern with the proposed TPL-001 language, as currently drafted, is that is appears circular. In particular, the proposed TPL-001-5 R1.1.2 first provides that planning models shall represent "[k]nown outages of generation or Transmission Facility(ies) . . . selected for analyses pursuant to Requirement 2, Parts 2.1.3 and 2.4.3 only." That is, the proposed TPL-001-5 R 1.1.2 appears to limit the scope of modeling requirements to a subset of analyses previously identified in TPL-001-5 R 2.1.3 and 2.4.3. TPL-001-5 R 2.1.3 in turn provides that qualifying studies shall include "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2." That is to say, the proposed TPL-001-5 R 1.1.2 appears to reference significant outages identified in the qualifying studies in TPL-001-5 R 2.1.3 while the required qualifying studies in TPL-001-5 R 2.1.3 will be based on those known outages identified in the established procedure set forth in TPL-001-5 R 1.1.2. As a result, the proposed language appears circular. That is, TP or PCs will not know which outages to select for their qualifying studies prior to identifying them using their established procedure. However, that procedure itself depends upon a prior identification of known outages in the qualifying study model run.

A similar issue exists in the proposed TPL-001-5 R 2.4.3. This section again requires studies of "P1 events . . . with known outages modeled as in Requirement R1, Part 1.1.2." However, will likely only be able to identify "known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events when concurrent with selected known outage(s)" by performing the analysis in TPL-001-5 R 2.4.3.

In lieu of adopting what appears to be a confusing and circular approach, Texas RE instead recommends that the SDT consider FERC's explicit invitation to define significant known outages based on parameters other than duration. In particular, FERC noted that NERC and the SDT could develop "parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings." (FERC Order No. 786, P. 43). The SDT could implement such a directive by requiring TPs and PCs to select known outages according to an established procedure or technical rationale that, at a minimum, establishes criteria based on MW or facility ratings for significant known outages. Consistent with this approach, the SDT recommends considering revising the proposed TPL-001-5 R 1.1 along the following lines:

1.1 System models shall represent:

1.1.1. Existing Facilities;

1.1.2. Known outages(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1 Establishes a criteria, supported by a technical justification, for identifying significant known outages based on MW or facility ratings; and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

Additionally, it is unclear whose "established procedure" per Part 1.1.4 is to be used, so additional clarification would be helpful.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
KCP&L incorporates its response to Question 4.	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	No
Document Name	
Comment	
National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001 and provides the following comment for consideration: Generation or Transmission Facilities outages can be scheduled on a time scale shorter than the Near-Term Transmission Planning Horizon. If a Facility outage previously not studied is selected per guidance provided in R1.1.2 and the selected Facility outage occurs within the Near-Term Transmission Planning Horizon, would that prohibit use of past studies to support the annual Planning Assessment (as otherwise allowed per R2.6)?	
Likes 0	
Dislikes 0	
Response	

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF and ACES comments.	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
In the last sentence of R1.1.2., SRP recommends changing the word “each” to “all” for the sake of clarity. Also, it is not necessary to specifically list sub-part 1.1.2.2., as there are already other criteria listed which are not solely based on outage duration.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
See comments from MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We have two concerns with the proposed changes: • As currently proposed, the TPL standard only requires P1 events to be simulated when assessing planned outages in the Near-Term Transmission Planning Horizon. However, this is inconsistent with NERC FAC standard FAC-014-2 R6, which require the Reliablity Co-ordinator to consider multiple contingencies when assessing these outages. Therefore, at a minimum, when the Planning Co-ordinator is assessing planned outages occurring in the Near Term Transmission Planning Horizon, they should simulate the contingences that the Reliablity Co-ordinator would simulate when assessing and approving these outages. Hence we propose to replace the requirement to simulate P1 events in R2.1.3 and R2.4.3 with a requirement to simulate the contingencies as specified per R6 of the current FAC-014-2 standard.	

- The current proposed requirement for selecting outages does not completely address FERC's order. FERC's order mentions that planned outages should not result in 'the loss of non-consequential load or detrimental impacts to system reliability', whereas the current proposed approach only addresses the loss of non-consequential load.

Likes 1	Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No
Document Name	

Comment

We propose the following changes to Part 1.1.2, "Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .":

- We suggest replacing the term, "scheduled", with the words, "planned to occur", because the term "scheduled" can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word "planned to occur" can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term "scheduled" is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator's scheduled outages.

- We suggest adding, "for applicable system conditions and year (s)", to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing "Transmission Planner and Planning Coordinator" with "Transmission Planner or Planning Coordinator" because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, "Are selected in accordance with documented outage selection procedures or technical rationale". If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
Comments: Addressing Order 786 without adding a tremendous amount of unnecessary study work is admittedly a difficult problem to solve. FMPA does not support the current draft language because it effectively requires that all outages, regardless of the duration, size or location of the facility (really regardless of any qualifier) must be studied. The reason for this is that non-consequential load shedding is rarely possible to identify without running the power system simulations. Thus in order for an entity to only study outages that cause non-consequential load shedding, that entity usually has to have already studied those outages. The suggested “filter” that the SDT is proposing requires that the Planner already know the result of the simulations. The proposed language introduces a standard requirement that, in practice, will result in entities being forced to “prove the negative” – that is, the focus will become defending how the Planner knew that certain outages would not cause non-consequential load loss. FMPA asserts that some reasonable qualifiers must exist, and must be used in an attempt to avoid requiring entities to prove the negative. Furthermore, conducting Planning studies on very short duration outages is a waste of time since short duration outages are much more easily (and therefore almost always are) rescheduled in the operations horizon to avoid transmission system reliability risks that are possible. Focusing on longer outage durations increases the likelihood that system performance conditions observed in the studies might actually occur in real time and focuses the study work of the planners more on projects that increase the flexibility of the system (e.g. giving the Operators more tools in their toolbox), rather than on trying to guess at operations horizon conditions or emulate Operations horizon planning work.	
Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy disagrees that the proposed changes meet the directives. The changes go beyond the scope of changes directed in Order No. 786 and will make Planners responsible for evaluating all known scenarios, even outages of limited duration (e.g. 10 minutes?). Also, the standard lacks clarity on whether outages of a Protection System should be considered as well. The lack of specificity regarding outages of limited duration, requires a Planner to study almost every possible scenario Operators may face in the Near Term Planning Horizon. Further, the proposed changes appear to push the standard to a fill in the blank status because it simply requires creation of “an established procedure”. The changes to 2.1.3 and 2.4.3 in addition to 1.1.2 appear to create circular logic to require Planners to know the seriousness of the consequences of a scenario they have yet to study.	

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

We propose the following changes to Part 1.1.2, “Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or Planning Coordinator for analyses . . .”:

- We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are not ‘hypothetical’ outages.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC’s directive for “NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…” [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	
Comment	

The changes meet the FERC directive but is restrictive on the transmission Planner/Planning Coordinator. In TPL-001-4, only outages 6 months or greater in the Planning Horizon needed to be considered. Requirement R1.1.2.2, as now written, does not permit exclusion solely based on outage duration, which means even one day or one hour outages that are in the near-term Planning horizon cannot be excluded. Perhaps the drafting can consider permitting exclusion of known outages based on some minimum duration (eg. outages less than 1 month maybe excluded, outages between 1 and 6 months may only be excluded if they are not expected to result in non-consequential load loss for P1 events, all outages greater than 6 months shall be included). This makes expectations more clear and avoids the need to develop a technical rationale.

Likes 0	
Dislikes 0	
Response	

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	
Comment	

We propose the following changes to Part 1.1.2, “Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .”:

We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can

- refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

MEC supports NSRF comments.

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

NVE recommends that R1.1.2 be modified to include outages that span the season being studied. For outages in the season being studied that are less than the entire span of the season, the Transmission Planner should be able to select which outage to study based on when in the study season the outage is to occur and the significance of the generation or transmission facilities involved in the outage for the area of the system they are located in.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No

Document Name	

Comment

OG&E recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and run the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

Subpart 2.1.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.1.1 and 2.1.2**, when known outages are scheduled."

Subpart 2.4.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.4.1 and 2.4.2**, when known outages are scheduled."

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	No
Document Name	

Comment

Comments: Other options could better address concerns in the FERC directive order No 786. The requirement to study outages of any duration in the Near Term Planning Horizon creates burden on the planning process to address the scheduling of outages rather than adequacy of BES infrastructure. Transmission planning is expected to determine performance deficiencies of the system and to mitigate them with planning solutions. Studying impacts of outages with 2 independent unplanned events on top of it would require the creation of additional base cases for (1) each outage in the 1-5 year horizon, or (2) creating cases which encompass all anticipated outages in a season. Next, one would then need to perform all analyses on top of such outages that would be included in the base cases. This essentially creates another layer of contingency analysis which can result in selective N-1-1-1 or more events deep depending on the method used. The results would likely be that impacts could be mitigated by: (a) scheduling appropriately to ensure outages do not overlap, or (b) moving outages into different seasons.

Unintended consequences could result. One example, although unlikely, would be proposing the construction of a transmission project that is built to allow for an outage of a facility for maintenance/rebuild which may be a rare outage occurrence itself. This project just adds a selective 3rd layer of transmission redundancy to the system to allow for reliable system operation during an outage if up to 2 other unplanned events occurred. While this exercise may be of importance to the scheduling of outages and identification of impacts of outages and contingencies, it is best handled by operations planning (operating horizon) which should instead handle the study and scheduling of planned outages beyond the operating horizon and into the Near Term Planning.

Alternative Draft wording for Requirement 1, Part 1.1.2 is provided below.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1. Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s);

1.1.2.2. Considers outage duration(s) but does not exclude known outage(s) solely based upon their duration;

1.1.2.3. Considers the significance of the generation and Transmission Facility(ies) involved in the known outage(s) for the area of the system in which they are located; and

1.1.2.4. Considers the expected load levels during the known outage(s).

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	

Comment

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can

- refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC’s directive for “NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…” [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System

Answer	No
Document Name	
Comment	

The phrase “expected to result” in Part 1.1.2.1 seems to imply that an entity must have studied the known outages to have an expectation of whether or not Non-Consequential Load Loss may occur. LES recommends the following alternate wording to Part 1.1.2.1: “Includes known outage(s) that **in qualified past studies have** resulted in Non-Consequential Load Loss for P1 events in Table 1…”

Likes 0	
Dislikes 0	
Response	

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	
Comment	

R1.1.1.2 requires planners to include known generation and transmission facility outages scheduled within the Near-Term Transmission Planning Horizon and to select the outages studied according to an established procedure or technical rationale. The requirement also states that outages should not be excluded solely based on outage duration. FERC Order 786 states that acceptable approaches for addressing the outage concern include decreasing the threshold to fewer months or including parameters for identifying “significant planned outages” (page 33).

Planners should review planned outages for the season under study and use technical rationale to determine whether an outage should be included or excluded from the study. Per FERC Order 786, planners should have the flexibility to exclude outages based on their technical rationale. Outages not deemed significant for the TPL assessment will be included in operations studies as the outage approaches.

CHPD has three concerns related to this proposed language regarding known outages in R1.1.2.:

1. The nature of the outage, i.e. scope of work, has an effect on the system but the transmission planners do not necessarily know how a facility will be removed from service. For example, for maintenance of a relay system, there are many options for performing the maintenance with impacts ranging from delayed clearing to no system impact at all: 1) simply take the maintenance outage with all other systems energized (relying on delayed clearing); 2) take the local terminal out of service (likely eliminating the delayed clearing risk); or 3) bypass the normal breaker and relays and feed the line from a bus tie or transfer breaker. CHPD requests the standard provide coordinators with flexibility to assume the scope and nature of outages.

2. For overlapping, un-coordinated outages, the Planning Authority or Transmission Planner should be given authority to, when appropriate, move the outages for the purposes of the planning study so they do not overlap. This activity is frequently performed for outages in the Operations Timeframe, but no construct exists to do this for outages in the Planning Horizon. The proposed Standard should provide such a construct.

3. For situations in which new infrastructure for a Corrective Action Plan cannot be built prior to an outage, e.g., an outage scheduled in 1.5 years requires a capital project that will take 3 years to build, the proposed Standard should allow for the interruption of firm transmission service. FERC’s concern was that properly planned outages should not lead to load shedding. FERC Order 786, paragraph 41. Allowing for interruption of firm transmission will allow critical outages to be taken while avoiding non-consequential load loss.

Likes 0	

Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	

Comment

These are planning studies, not operating studies. Outage coordination studies are currently done by the operations department as part of operations seasonal planning. Adding outage coordination studies to the Near Term Planning Horizon [1-5 years] will increase the planning work load without any real reliability improvement. The reason being that planned outages are currently part of transmission planning in both the Near and Long Term Horizons. It is a matter of understanding the steady-state contingency results. When looking at future system behavior, N-2 steady-state contingency analysis will reveal system performance with a single BES element out of service followed by a P1 event. Two element are out of service N-2. This is only a starting point. When N-2 contingency analysis does not show any performance violations, the system should be able to remove BES elements from service without issue. If a performance violation is found, then further analysis is required (N-1-1). We do not need a new requirement.

If the requirement is added, the stability portion should be removed. Including stability analysis to the requirement will make it overly burdensome and will not improve reliability. Stability analysis software is not well suited for automation and the TPs and PCs can not reasonably be expected to perform stability analysis for every valid P1 contingency for each possible BES outage. The language of the requirement calls for contingencies which are "expected to produce more serverer system impacts". The only way to know the expected stability impact is to study it. Therefore, the requirement actually requires all planned outages to be studied using stability analysis and then to use those results to support the selection of a contingency subset to be studied. This is a circular argument. Stability analysis of planned is not needed for reliability.

Likes 0	
Dislikes 0	

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	

Comment

Tri-State partially agrees but has some reservations regarding the specific language and overlaps with existing P3 and P6 contingency categories.

Requirement 1.1.2.2 runs counter to Requirement 1.1.2 which allows outage selection based on technical rationale. Technical rationale would include time-dependence. The inclusion of major outages regardless of time duration effectively adds an outage coordination aspect to performing the TPL assessment. Outage coordination is already performed by Transmission Operations.

Requirement 1.1.2 effectively describes a category P3 or P6 contingency.

Likes 0	
Dislikes 0	

Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

AZPS respectfully asserts that the proposed criteria under Requirement R1, Part 1.1.2 presents an overly complicated response to the Commission's directive in Order 786, Paragraph 43. Specifically, the Commission's directive allowed for the response to the directive to be a simple reduction of the 6 month time period. Such reduction would provide objective criteria for the entire industry to utilize to determine whether or not planned outages should be included in their planning assessment. AZPS is concerned that the proposed criteria under Part 1.1.2 is subjective in nature and could result in the potential for inconsistency relative to the inclusion of outages in planning assessments, e.g., outages of three (3) months or less could be implicated by some entities despite such outages creating unnecessary study burden with little to no reliability benefit wherein other entities could exclude such short-term outages.

To ensure that the criteria provides more objectivity relative to the inclusion of outages in planning assessments, which would increase the overall consistency and value of planning assessments generally, AZPS recommends that the SDT reconsider the currently proposed criteria and replace it with criteria that requires outages to be included where such outages meet a definitive time period of "more than 3 months." AZPS respectfully asserts that short term outages should be studied and prepared for in the Operating horizon and not in a planning assessment and, further, that the potential for inconsistency between planning assessments would reduce the proposed reliability benefit anticipated by the currently proposed criteria. For these reasons, AZPS recommends replacement of the currently proposed criteria with a simplified criteria requiring inclusion of outages that are anticipated to last more than three months.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA appreciates that the reference to consultation with the Reliability Coordinator has been removed and that "Transmission" was added to Near-Term Transmission Planning Horizon.

For R1.1.2.2 BPA does not believe it would be reasonable to require justification for every known outage that is not included. The way R1.1.2 is written, it seems to imply that an outage excluded based on duration should also not meet the established procedure or technical rationale.

Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	

The language in Part 1.1.2 is fine; however the language added to R2 Parts 2.1.3 and 2.4.3 that is referenced in Part 1.1.2 is confusing. Page 8 of the posted Technical Rationale document contains the rationale for changes to R2 Parts 2.1.3 and 2.4.3:

"Consistent with FERC's directive, the drafting team modified Requirements **R2 Parts** 2.1.3 and 2.4.3 to further recognize the intent to limit required study to only those known outages that are expected to produce severe System impacts on the PC/TP's respective portion of the BES."

LSPT agrees with this rationale. However, the changes to Parts 2.1.3 and 2.4.3 do not accomplish this objective. Since both 2.1.3 and 2.4.3 have the same added language, the concern is illustrated in 2.1.3 only, which states the following regarding the analysis required by the Planning Coordinator or Transmission Planner, with the added language bolded:

2.1.3. P1 events in Table 1 **expected to produce more severe System impacts on its portion of the BES**, 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.

The proposed change allow the PC/TP to **not** evaluate all P1 events; the PC/TP must only evaluate those P1 events in Table 1 "expected to produce the most severe System impacts on it portion of the BES." In other words, the P1 events in combination with "known outages" that produce the most severe System impacts may be a different set of P1 events..

LSPT's proposed changes to 2.1.3 (and correspondingly to 2.4.3) will correct this unintended consequence:

2.1.3. P1 events in Table 1, with known outages **that are expected to produce more severe System impacts on its portion of the BES** modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	

We understand the need to address FERC Order No 786; however, the additions to 1.1.2 are creating additional unnecessary modeling work that we do not believe provides additional value to reliability.

Likes 0	
Dislikes 0	

Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	No
Document Name	
Comment	

OUC believes the proposed Requirement 1.1.2. leaves too large of ambiguity in what needs to be tested. The intent of what is required to be tested is not clear, and appears on the surface to overlap significantly with the Operations Planning realm. The current standards provide enough parameters to include outages into the base case (using the 6 month outage duration as a threshold). The proposed changes reads as if it's requiring long-term transmission planners to study operational planning studies under the "Near-Term Transmission Planning Horizon". OUC does not believe the TPL requirements should include operational planning studies that should otherwise be included under the TOP standards (i.e. TOP-002-4). By not defining an outage duration, the requirement now appears to welcome any and all outage scenario testing, which should otherwise be completed under the TOP standards. Although Requirement 1.1.2.1 was added to limit the outages selected, for most it would be unclear what scenarios would result in non-consequential load loss, thus not providing enough of a parameter to limit the outages needed to be tested.

Suggestion: OUC would suggest keeping the outage length as a parameter in order to filter the outages that should be studied in the Near-Term Planning Horizon. In understanding the 6 month outage duration not being inclusive of what the drafting team may be looking for, perhaps limiting the outage duration to 3 months would include enough of the key outages that should be studied, while not including all outages which would otherwise need to be analyzed under Operations Planning scenarios.

Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	

Answer	No
Document Name	

Comment

As proposed, we believe that R1.1.2.1 involves the creation of hypothetical outages to evaluate and include in the transmission assessment.

From the Order 786, paragraph 42, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." Most transmission maintenance outages are scheduled in the operating horizon, after considerable review and analysis of expected system conditions in the operating horizon. These outages may be daily, weekly, or of longer duration, but still they are planned and scheduled in the operating horizon and not the planning horizon. Therefore, from a planning perspective, few if any transmission outages will be included in the base case peak or off-peak models for analysis and development of the Planning Assessment because these maintenance outages have not been scheduled in the planning horizon.

The Commission goes on to state in paragraph 44 that "these potential planned outages must be addressed, so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon". In other words, the Commission wants us to speculate on the start and stop times of the maintenance outages, effectively creating hypothetical outages to consider for analyses. From our perspective the language of this paragraph of Order 786 is ambiguous.

The Commission also stated in paragraph 44 that category P3 and P6 contingencies do not cover generation and transmission maintenance outages, but during the webinar, it was suggested by a member of the standard drafting team that the allowance of system adjustments following the planning maintenance outage event was the reason for FERC's disapproval. Is it the drafting team position that if the analyses were performed without system adjustments between the outage events, then FERC would not object? We did not read that response in Order 786 and request that the Standard Drafting Team provide reference that analyses of P3 and P6 events without system adjustment, other than make-up power, would provide an acceptable method for determining system adequacy during maintenance, planned or hypothetical, outages. However, we question why generation redispatch or other operating guides cannot be developed, if needed, to facilitate the performance of maintenance outages in the planning or operating horizons.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

Requirement 1, Part 1.1.2.1., does not provide a clear demonstrable criterion for outage selection. In order to conclusively determine “expected” Non-Consequential Load Loss during an N-2 event, studies must be performed to determine the response of the system. Therefore, this requirement, as written, implies that the Transmission Planner must consider *all* known outages. In Order 786, paragraph 43, FERC suggested that a selection

parameter of facility ratings could be used. Use of a facility rating threshold in the standard would provide needed clarity to Transmission Planners and result in greater consistency.

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO agrees with the changes in Part 1.1.2 with the exceptions noted in the response to Question 4 below.	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
There is no one size fits all country wide method of identifying which known outages are best included in this section. The SDT has put in place a mechanism that allows reasonable local tailoring to the list of known outages by the TP or PC.	
Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Section 2.7, related to Corrective Action Plans – there appears to be an incorrect reference to Section 2.4.3. This reference should be changed to the new section 2.4.4	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Landis - Platte River Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed implementation plan?

Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	

The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.

However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.)

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**.

Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	

Jeff Landis - Platte River Power Authority - 3	
Answer	No
Document Name	
Comment	

PRPA supports JEA comments.

The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.

However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different

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challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.)

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.

Likes 0	
Dislikes 0	

Response

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
Should be 2 years longer.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
We are not in agreement with the changes, therefore the implementation dicussion is a mute point at this time.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	

Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No

Document Name	
Comment	

Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new ‘known outages’ and ‘non-redundant’ Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF

Answer	No
Document Name	
Comment	

Duke Energy does not agree with the proposed Implementation Plan. Depending on system conditions, it is anticipated that when using Dynamic Load Modeling, that an entity could see a great number of its Facilities fail the performance requirements. Failure of the performance requirements could result in significant upgrades, which take time to implement. With the potential for significant upgrades to a majority of applicable Facilities, Duke Energy cannot agree with the Implementation Plan proposed.

Likes 0	
Dislikes 0	
Response	

John Bee - Exelon - 3

Answer	No
Document Name	
Comment	

See Exelon TO Utilities Comments

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken

Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
FMPA supports the comments of JEA on the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
Louisville Gas and Electric Company and Kentucky Utilities Company (LKE) supports providing Planning Coordinators (PCs) and Transmission Planners (TPs) 36 months until the effective date of the Standard to develop a procedure or technical rationale for selecting known outages of generation and Transmission Facilities, a process for establish coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis, and additional base case models and analysis. However, LKE believes that requiring "the planned System [to] continue to meet the performance requirements in Table 1 until 96 months after the effective date of Reliability Standard TPL-001-5" is too long. The three years before the effective date plus 8 years is 11 years. Other NERC standards do not have an 11 year time frame to fix an identified reliability risk to the BES.	

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	

Comment

See comments from MRO NSRF.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	

Comment

GRE agrees with the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	

Comment

Since we have concerns with the ambiguity of the proposed P8 event (see our comments to question #1), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.

Likes 0	
Dislikes 0	

Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

KCP&L recommends extending to 60-months the preparation period prior to the effective date of the Standard.

In the alternative, provide flexibility or a process to extend the 36-month period based on the TP and PC's evaluation to implement the revised TPL-001-5 Standard.

Concern

The proposed Implementation Plan's time periods do not fully consider the differences in system sizes, complexity, and design elements.

Additionally, with the Standard's assessment scope expansion, the periods offered in the Plan need to consider barriers entities face staffing or contracting for the qualified personal to complete studies and implement CAPs.

KCP&L identified activities it anticipates will be required under the Standard that make the Plan's time periods insufficient to complete implementation of the proposed Standard. Here is an example:

- Changing and updating contingency lists will extend beyond the 36-month period because of the complexity and size of the undertaking and required vetting.

Beyond a single implementation activity, the implementation of the revised Standard will require long-duration, contingent, inter-related activities that, taken individually may fall within the 36-month period but, to collectively complete all the activities, will extend beyond the 36-month period. For example:

1. The best-case scenario to update and test dynamics software will take at least 12-months. The estimated period is without consideration of challenges to:

- Schedule the software upgrade and testing;
- Incorporate the additional P8 events and the re-alignment of Extreme events into the software; and
- Address the many "small" changes that will affect the planning models and assessments.

The proposed revision's specific and required assessments are contingent on updating and testing dynamics software. The period to complete the upgrade and assessments we easily see extending beyond the 36-month proposed implementation period.

A 36-month period to complete required assessments seems arbitrary when placed against the wide spectrum of applicable systems. In consideration of system differences, we recommend the 60-month period or, in the alternative, a process to extend the period based on TP and PC's evaluation to implement the revised TPL-001-5 Standard.

Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE appreciates the SDT's efforts in putting together the proposed Implementation Plan. Texas RE notes that, in its experience, registered entities have had significant issues understanding and following implementation plans. Texas RE therefore strongly encourages the SDT to carefully review the proposed Implementation Plan to ensure that is not ambiguous, vague, or confusing to understand.

To that end, Texas RE notes two aspects of the proposed implementation plan that could lead to potentially significant industry confusion. First, Texas RE notes that in establishing the requirement to complete planning assessments 36 months following the effective date of the standard approval, the proposed Implementation Plan is silent regarding the specific Standard Requirements that are actually implicated. Texas RE recommends that the SDT not merely rely on references to "planning assessments," but actually insert specific references to the Requirements subject to the 36-month planning assessment compliance threshold to reduce any possible ambiguity. Second, the proposed implementation plan provides that the requirement to implement Corrective Action Plans (CAPs) to be "the first calendar quarter 84 months following applicable regulatory approval of TPL-001-4." The effective date of the FERC Order approving TPL-001-4 is December 22, 2013. As such, the CAP requirement would, on its face, be due on March 1, 2020. Because TPL-001-5 will not become effective for at least 36 months following any applicable regulatory approvals, this requirement would trigger *prior* to the effective date of the proposed TPL-001-5 Standard. This appears to be in error, and Texas RE suggests that the SDT revise this aspect of the implementation plan accordingly – perhaps by inserting a reference to TPL-001-5 instead of TPL-001-4.

In addition to these issues, Texas RE presently understands the implementation plan, as currently drafted, to provide the following glide path to full implementation of the proposed TPL-001-5 Standard:

First calendar quarter 36 months following regulatory approval.

· The effective date of the standard is the first day of the first calendar quarter 36 months following the effective date of the applicable governmental authorities order approving the standard. This date serves as a starting point for the implementation plan.

· In accordance with the Initial Performance section, applicable entities must complete the planning assessment without CAPs by the effective date of the standard, or 36 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes there is no requirement mentioned. In the interest of clarity and not being vague Texas RE strongly recommends the implementation plan specify which requirement this date refers to.

60 months following regulatory approval.

· In accordance with the Initial Performance section, applicable entities must develop any required CAPs 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 b, c, and d, and P8 by 24 months following the effective date of the standard, or 36 months plus 24 months, or 60 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes this is also indicated in the Compliance Date section.

For 84 months following regulatory approval

o Texas RE noted the issue with the standard version above in reference to the Note Regarding CAPs. Assuming this should indeed specify TPL-001-5, rather than TPL-001-4, CAPs applying to the specified categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Form Transmission Service.

132 months following regulatory approval

o In accordance with the Compliance Date section, entities have 96 months from the effective date to end the use of CAPs developed to address failures to meet Table 1 performance requirements for P5 and P8 events only. The way this is written indicates entities have 36 months following the effective date of the applicable governmental authorities order approving the standard *plus 96 additional months* to end the use of CAPs. Is it the SDT's intent that this be *132 months from the effective date of the applicable governmental authority's order*? This timeline seems excessively long and would unnecessarily burden registered entities to prove it is doing anything to support the reliable operation of the grid based on an assessment.

In addition to the two confusing aspects noted previously, Texas RE noticed additional areas in which this implementation plan lacks clarity.

· First, the implementation plan uses different but similar terms: Effective Date, Compliance Date, and Initial Performance Date. While implementation plans in the past have used Effective Dates to indicate the starting point at which all activities are based upon, the use of the Effective Date is inconsistent in this plan. The implementation plan calculates when applicable entities must do planning assessments from the effective date (must be by the effective date for planning assessments without CAPs) as well as it calculates when any required CAPs 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 b, c, and d, and P8 must be developed (24 months following the effective date). It is *not* used to calculate the date by which applicable entities must end their use of CAPs, nor is it used to calculate the date by which CAPs should not include Non-Consequential Load Loss and/or curtailment of Firm Transmission Service (see Note Regarding CAPs). This date is calculated based upon the effective date of the applicable governmental authority's order. To improve clarity, the effective date should be used consistently.

· Texas RE inquires as to the difference between the terms Compliance Date and Initial Performance Date. The Compliance Date section contains the same information as the second paragraph of the Initial Performance section. Are they intended to mean two different things since two different terms are used?

· It is also unclear to which requirements the actions refer. Are we to assume that if the requirement is not mentioned specifically, it is enforceable on the effective date of the standard?

Likes 0	
Dislikes 0	
Response	

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	

Comment	
The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5. However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, We do not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities. We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.) Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, We recommend NERC survey the industry (PCs, TPs and Facility owners) with another ***Request for Data Under Section 1600 of the NERC Rules of Procedure*** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ***ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)***.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA supports JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	

Answer	No
Document Name	
Comment	
See comments below.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SCE expects that bullet D in the revised footnote 13 as currently written will bring over half of the existing SCE protection systems into scope for assessment of delayed clearing for P5 events. Without a completed assessment of the impact to reliability, SCE expects that some substations will require Corrective Action Plans to bring protection systems to full redundancy or system reliability within performance requirements. SCE proposes that the implementation plan keep the initial 36 months until Assessments must include the new models and studies but increase the time for developing Corrective Action Plans for P5 and P8 contingencies to an additional 60 months instead of 24. Similar to when TPL-001-4 first became effective, certain categories of contingencies were recognized as needing additional time for Transmission Planning entities to raise the bar on system performance. SCE proposes that the same latitude be applied to TPL-001-5's proposed higher standard of system performance.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light supports JEA comments.	
Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
The implementation plan requires Oncor to perform contingency analysis for P8 contingencies and develop a Corrective Action Plan for any issues resulting from a P8 contingency. Oncor does not agree with the requirements pertaining to P8 contingencies as outlined in the first comment above. If the P8 contingency is adopted, the implementation time needs to be longer due to the effort required to gather the required information and perform the first analysis.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
The timeframes outlined in the implementation plan appear to be adequate to respond to the new requirements.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

The implementation plan seems reasonable from a planning perspective. Depending on the number of system protection upgrades needed, the completion of these upgrades by the desired date may be a challenge.	
Likes 0	
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	Yes
Document Name	
Comment	
While we do not agree with the additional requirements, we believe 24 months is reasonable.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	

References to P8 would need to be removed from the implementation plan if the proposed changes are made to move the P8 events back to Extreme Events.

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
The implementation plan is ok other the plan associated with P8. Manitoba Hydro doesn't agree that P8 should be added.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The Implementation Plan allows sufficient time to coordinate CAPs with external entities and meet compliance	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

We agree with the implementation timeline, but the proposed revisions still need some work.We agree with the implementation timeline, but the proposed revisions still need some work.

Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	
Document Name	
Comment	
LES supports the comments provided by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	
On page 2 of the implementation plan, there is a statement in the third paragraph which may require some clarification. In "…failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed" does the phrase "may not be mitigated" imply that interim Operating Procedures will not be allowed, or is this an acknowledgement (and acceptance) that there may be instances in which an interim Operating Procedure may not be sufficient to meet the System performance requirements? We assume the second interpretation is what was intended, but it is recommended that this statement be clarified to eliminate the possibility of misinterpretation.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
The 60 month implementation plan is appropriate as a significant amount of protection and control related data and design drawings will have to be acquired and reviewed in order to facilitate the ability to study the required additional dynamic simulations.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed revisions to TPL-001-4?

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT would recommend two further revisions.

First, ERCOT recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete ", at a minimum:" from section 1.1.2 and replace with the full text of proposed 1.1.2.2 ("does not exclude known outage(s) solely based upon the outage duration.").

2. Delete sections 1.1.2.1 and 1.1.2.2.

Second, ERCOT recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are "expected to produce more severe System impacts on [the responsible entity's] portion of the BES." However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.1.3.

2. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.4.3.

Likes 0	
Dislikes 0	

Response

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

See comments in response to question 2.

Likes 0	

Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

Oncor believes that the definition of 'non-redundant components of protection system' per Table 1, item 13 is consistent with FERC order 754 (2012) as well as NERC's technical paper on 'Redundancy of Protection System Elements' (2008) – However, this definition coupled with category P5 and newly added category P8 expands much beyond FERC Order 754 for the following reason:

- FERC Order 754 data request limited the buses to be analyzed by the voltage level and number of circuits associated with the bus. These criteria clearly were targeted to pick the more critical stations from reliability and stability stand point.
- The enforceable definition of the non-redundant protection scheme without general guidelines on where to apply such definition, in essence expands the assessment to the entire system without consideration to the criticality of the elements. Generally speaking, it is more common to have non-redundant schemes at smaller stations (lower kV, fewer transmission circuits, remote locations, etc.), as they have minimum system impacts during faults, and tend to have only localized issues (or outages that are not an issue).

Oncor recommends the assessments per category P5 and P8 should be limited to defined critical stations similar to FERC 0rder 754.

The redundancy as per Table 1-13(a) through Table 1-13(c) are reasonable replacement of 'relay failure' as per TPL-001-4. However, Oncor is not in agreement with Table 1-13(d) for the following reason:

In Oncor's experience, failure of DC control circuitry is an unlikely event in general. Additionally, if the circuits were to fail, the result would be a breaker failure (stuck breaker) resulting in operations of breaker failure schemes – avoiding remote delayed clearing which is much longer than breaker failure delay. Oncor believes this requirement is not sufficient justification to require assessing DC control circuitry.

Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

We agree with some of the revisions, but believe the establishment of a P8 event is not appropriate, the proposed criteria for including planned outages reaches too far into the Operating Horizon, and that Footnote 13 should be made clearer to avoid varying interpretations.

Likes 0	

Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light supports JEA comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2). This revision will address the Commission's directive from Order No. 754 and is consistent with the recommendations from the Joint Report regarding the three phase faults.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. We believe Requirement 2, Part 2.1.3 and Part 2.4.3 should complement our previous recommendation for Requirement 1, Part 1.1.2 on basing significant planned outages according to registered entity-selected facility ratings. The required studies should allow registered entities flexibility on which planned outages are necessary for P1 event studies, particularly those outages that incorporate Facility expansion, construction, or rebuilds and other solutions documented in Corrective Actions Plans.
2. The reference to open circuit within Footnote 13c needs further clarification. The term "dc supply" is ambiguous and needs to confirm the accepted configuration for substation control houses. Will this require two batteries, two separate battery chargers for a single battery bank, or

onsite backup generation as the accepted configuration? The technology currently available for detecting open circuits is problematic and can introduce addition points of failure when in service. We recommend clarifying the reference to read "A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for abnormal DC voltages."

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No
Document Name	

Comment

The California ISO generally agrees with the proposed revisions to TPL-001-4, but would recommend two revisions.

First, the California ISO recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786.

The California ISO recommends the following specific revisions based on the foregoing concerns:

1. Delete ", at a minimum:" from section 1.1.2 and replace with the full text of proposed 1.1.2.2 ("does not exclude known outage(s) solely based upon the outage duration.").

2. Delete sections 1.1.2.1 and 1.1.2.2.

Second, the California ISO recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are "expected to produce more severe System impacts on [the responsible entity's] portion of the BES." However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted.

The California ISO recommends the following specific revisions based on the foregoing concerns:

1. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.1.3.

2. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.4.3.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment	
SCE's key disagreement with the proposed revisions is the language of bullet D of Footnote 13. SCE provided comments on bullet D during draft 1 regarding a monitoring provision like that contained in bullets B & C. The drafting team provided feedback as to its decision at that time due to limitations of PRC-005 monitoring. For draft 2, SCE responded to the direct feedback with additional substantive information for consideration regarding the role PRC-005 monitoring that allows extended maintenance intervals because the equipment will indicate if there is an issue. However, the drafting team didn't provide a rationale for the continued rejection of SCE's proposal to exclude control circuitry through the trip coils that are monitored and reported. Respectfully, SCE wishes to reiterate the reliability value in monitoring control circuitry combined with higher periodicity testing requirements for components such as electromechanical lockout relays required by PRC-005.	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
• The NERC Drafting Team should consider limiting single points of failure at Generation Facilities and develop a criteria for applicability to GOs (Example: Limit GO applicability to relays associated to interconnection points and not all relays that are part of PRC-005). It is understood that this Standard does not directly apply to the GO under the Applicability section of this Standard but it appears they could ultimately be required to create Corrective Action Plans (CAPs) by the Transmission Planner or Planning Coordinator for non-redundant components of a Protection System. Also, singular generation units are already accounted for in Planning Assessments so single points of failure at these locations should be exempt from this analysis. Additionally, the SDT should consider only requiring GOs to identify single points of failure to be included in Planning Assessments but not require GOs to develop Corrective Action Plans (CAPs). The proposed revisions as written, when applied to GOs, would provide little reliability benefit but could potentially result in significant cost associated with upgrading Facilities. • Single protective relays and single control circuitry referenced in footnote 13 are prevalent for equipment at voltages 100kV -229kV and generally do not meet the redundancy requirements in the proposed revisions of this Standard. The SDT should consider making footnote 13 applicable to equipment at 230kV and above. • Single communication systems referenced in footnote 13 should be clarified by the SDT and state backup communication can use time delay functionality (does not use communication system) if relays can clear normally. The current wording implies that two independent communication paths are required to report issue back to the Control Center. Additionally, the SDT should consider allowing weekly communication checkbacks that report back to the Control Center as a method to meet the communication requirements in footnote 13. • A single dc supply referenced in footnote 13 would add significant cost with little benefit for dc supply open circuit monitoring in real-time. The SDT should consider addressing dc supply open circuit during quarterly battery maintenance in PRC-005-6 to reduce cost impact to industry. The estimated total cost for installing dc supply open circuit monitoring would be roughly $50,000 per location.	
Likes 0	
Dislikes 0	
Response	

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	No
Document Name	
Comment	
Hydro One still has concerns with the following points regarding Footnote 13: 1) 13c – The term “open circuit” is not clear. Please provide clarification of the term and an example of how it is typically monitored in the supplementary material for better understanding. 2) 13d – We recommend that a single trip coil that is “monitored and reported at a Control Center” be treated the same way that communication systems (Footnote 13b) and DC Supply (Footnote 13c) are treated (to meet the redundancy requirement).	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA supports JEA’s comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
See responses to Questions 1 and 2.	

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	

Comment

We disagree with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission’s directive from Order No. 786 Paragraph 40.

The clarifications added for entity’s spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission’s directive from Order No. 786 Paragraph 89.

The replacement of the ‘Special Protection Systems’ with ‘Remedial Action Schemes’ is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission’s concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

While there are many improvements implemented in this posting, there are still some modifications that should be made as articulated in the responses to the previous questions in this Comment Form, and additionally:

Requriement 2, Part 1.5, we suggest modifying the following phrase (see BOLD font for modifying word): "…….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….." to"…….the impact of this possible unavailability on System performance shall be assessed. The **assessment** shall be based on analysis performed for the P0, P1, and P2 categories identified in Table 1…..".

Part 2.1.3 and 2.4.3 - We propose alternative text for Part 2.1.3 and 2.4.3, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with the **selected** outages modeled in Requirement R1, Part 1.1.2, under those System peak, Off-Peak, **or other** conditions when **the selected** outages are scheduled **or planned to occur**."

The System peak or Off-Peak models will normally be suitable for the Part 2.1.3 requirement. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using of other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models.

The addition of the word, "planned", allows the inclusion of outages identified by PCs or TPs that are necessary in the planning horizon to implement Corrective Actions Plans – as most if not all are likely not to be scheduled yet.

Item h in the first page of Table 1 should be relocated to "after Item e" but before the Steady State section. Then re-alphabetize accordingly.

Footnote 14 - We propose adding a **Footnote 14** that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. "

Even with the relaxation of required performance, the rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onerous (P8).

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

In addition to the issues noted in #2, Texas RE noticed the following:

- In Part 3.4, Texas RE is concerned that allowing registered entities to select which P1 events are “expected to produce more severe System impacts”, registered entities have the flexibility to ignore P1 events without determining the actual impact of the events. Texas RE recommends all P1 events should be selected.
- In Table 1, Texas RE noticed P8 is not listed in Steady State Only or Stability Only. Is it the SDT’s intent to leave it out of those conditions?

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

KCP&L recommends the Standard include language that will allow establishing the scope of contingencies in dynamics to a specific area local to the equipment.

Concern

The proposed revisions substantially expand required assessments and studies, including long-lead time equipment into dynamic analysis, and consideration of all outages—without limitation—during the assessment process.

The company recognizes the proposed revisions reflect the Orders’ language requiring consideration of outages without limitation, and so forth, but the language to satisfy the Orders require markedly greater resources.

Recommendation

KCP&L suggests adding language that provides an efficiency, or like efficiencies, in the assessment process and addresses the Standard Requirements. We suggest the following:

Requirement language or guidance that establishes the scope of contingencies in dynamics to a specific area local to the equipment. This provides an efficiency in the evaluation of contingencies by allowing the TP to draw a bus-ring around applicable equipment and evaluate contingencies within a smaller, yet relevant, range.

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	No
Document Name	

Comment	
National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001, including the creation of the proposed P8 event. We believe that, in particular, Footnote 13 still includes some ambiguity in defining what protection performance is needed to reduce the risk of reliability impact from Single Points of Failures, and would like to provide the following comments: Does "spare equipment strategy" mean the existence of at least a single spare for major transmission equipment that has a lead time of more than one year; and does Requirement 2.4.5 imply that the existence of such a spare would eliminate the need to assess the impact of the possible unavailability of such equipment on System performance? If so, then Requirement 2.4.5 should be written this way. As currently written, Requirement 2.4.5 lacks clarity. Every reasonable "spare equipment strategy" for equipment with a lead time of one year or more could result in the unavailability of such equipment; it is a matter of probability. For example, an Entity with 100 large power transformers could have a spare transformer strategy of maintaining one system spare. However, it is possible that two transformers could fail during time span of one year. With only one spare, the Entity would be exposed to operating the system for up to one year with one less transformer than designed. Even if the Entity has four (4) spares, it is still possible that five (5) transformers could fail during one year (albeit with much lower probability), which would leave the Entity similarly exposed. Greater clarity is required for Requirement 2.4.5, as is more criterion development. It is not fully clear as to what constitutes "comparable" in the context of comparable Normal Clearing times in Table 1 Footnote 13 Part a. Please also clarify what constitutes an "alternative" relay, beyond allowing for response to non-electrical quantities. What if alternative relay does not provide the same clearing time as the primary relay (e.g., the alternate relay is an impedance relay with longer Zone 2 timer, or the alternative relay is an overcurrent relay, while the primary relay is an impedance relay). Could any relay classified as an "alternative" relay be considered as 'redundant', and therefore Footnote 13 would not apply? We would like the SDT to provide guidance on what constitutes "comparable" Normal Clearing times and an "alternative" relay, e.g., in a 'Guidelines and Technical Basis' section. Even after including auxiliary relays and lockout relays, it is still not fully clear what the term "control circuitry" includes. As written, it seems that "control circuitry" (apart from wiring) includes auxiliary relays and lockout relays. Since we believe it could be advantageous to provide a more 'formal' definition of this term, we suggest providing additional guidance in a 'Guidelines and Technical Basis' section and/or including a definition for "control circuitry" in the 'Glossary of Terms Used in NERC Reliability Standards'. As another Entity brought up during the NERC webinar on March 22, 2018, why does the exclusion (provided per Footnote 13 Part b) for communication systems not also extend to single protective relays (referred to in Footnote 13 item a), if monitored or reported at a Control Center? We also believe it would be of value to consider requesting entities to document the rationale regarding considerations regarding non-redundant components of a Protection System evaluated per Footnote 13.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

It is recommended to consider revising Sections 3.2 and 3.5 in a similar manner to the proposed revisions to Sections 4.2 and 4.5.

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1….." Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Additional Comment for consideration, related to clarification of the Standard:

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski

Answer	No
Document Name	

Comment

GRE agrees with the MRO NSRF and ACES comments and:

13b. Single communications system

- Monitoring a single communication scheme does not provide the same robustness as having a redundant communication scheme.
- Communication failures in blocking schemes do not result in delayed clearing.
-
- It is important for planning to identify locations where delayed clearing of faults (such as in zone 2 time) could lead to cascading outages or stability concerns. If faster clearing times are required, these elements should have redundant communications installed. In many companies, these studies are already being performed. If not, the requirement to study the impact of failures of single communication schemes could drive a company to identify where redundant communications are required.
-

- The intent of the standard is to study failures/contingencies which are most impactful to the BES. Typically, single communication schemes are in place to limit damage, improve coordination and as a good design practice. If a communication scheme is installed for these reasons, the "Normal clearing time" of the protective system may not be necessary to maintain system stability or prevent cascading outages.
-
- The use of the phrase "Normal Clearing time" should be changed to "time required to maintain system stability" or "critical clearing time" or "time to prevent misoperation, cascading, or unintentional islanding". Otherwise, non-redundant communications systems which were not installed for the purpose of maintaining stability would need to be evaluated (or monitored). Such evaluation would be an unnecessary burden.

13c. Single station dc supply

- How common is the monitoring of a battery open circuit condition? FERC Order 754 report says it was not common at the time of the order to have redundant batteries, and it is probably not that common now to have redundant batteries or open circuit monitoring. Without open circuit monitoring, it is possible that a charger might mask an open circuit in the battery. Open circuit monitoring is possible but is not universally applied where there are single batteries.

- FERC Order 754 only applied to 200 kV substations or higher. The number of substations lower than 200 kV without redundant batteries will be substantially higher.

- GRE's standard design for new 230 kV substations or higher is to install redundant batteries, but we have many existing facilities that have one battery bank with redundant AC supply. Monitoring for open DC supply has not been considered in the past when defining a redundant DC supply.

- Periodic open circuit testing as required by PRC-005 will likely not meet the requirement of open circuit monitoring.

- This requirement seems likely to drive industry to either retrofit existing installations with open circuit monitoring or to install redundant DC supplies. Is this the appropriate place to drive that decision, for a high impact/low risk battery failure? This could be a significant impact, and it appears that this impact may not be fully understood in the context of reviewing this standard.

- Should a risk based approach be considered—an open circuit battery failure is a low risk, high impact event?

13d. Single control circuitry

- As written, this seems to apply to components (coils, auxiliary relays) and wires.

- Verifying where there is single control circuitry could be costly—there are many legacy installations which may not follow present design practices and would require some type of manual review of substation drawings.

- Consider audit evidence for this requirement. Documentation of present design standards which meet the requirement is practical, will it be sufficient?

- A risk based approach to this requirement which limits the review to redundancy of components instead of wires may be practical. The failure rate of wiring is far less than that of components.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No

Document Name	
Comment	

SRP agrees with the reliability goals of TPL-001-5, but also has some recommendations. SRP recommends moving the final sentence of 3.5. to the end of 3.2., just as was done between 4.5. and 4.2.

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	
Comment	

See comments from MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	
Comment	

Please see Comment #1 and Comment #2

Likes 0	
Dislikes 0	
Response	

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	
Comment	

Footnote 13, item c lacks clarity as to what constitutes a single station d.c. supply. Typical stations are configured with two components that operate as a single d.c. supply system – an inverter and battery bank. Each of these components provide some redundancy to provide d.c. load for failure of the other component, which could be interpreted as meeting the requirements for a redundant system with no further monitoring required per Proposed Reliability Standard TPL-001-5 Table 1. However, if the entire d.c. supply system is considered a single component, then the requirement to monitor for open circuit is not sufficiently clear to determine if the inverter, battery, or load must be monitored for open circuit. PPL NERC Registered Affiliates requests clarification to Proposed Reliability Standard TPL-001-5 Footnote 13, item c – specifically, as to what constitutes a single station d.c. supply to eliminate ambiguity of the requirement to monitor for open circuit needs.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	

Comment

Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.”

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”.

Same explanatory text as Part 2.1.3.

Table 13, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement. The normally long open circuit monitoring intervals is expected to make the open circuit monitoring exception irrelevant.

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

Footnote 14 - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

In addition to the comments written above in answer to Questions 1 and 2, FMPA notes that the questions in this comment form do not cover all of the changes. Order 786 required more than just the changes to Requirement 1, part 1.1.2. There is also the addition of Requirement 2.4.5, adding stability analysis as required per an entity’s Spare Equipment Strategy. FMPA notes that while studying these events in steady state using P0, P1 and P2 events, doing so for stability doesn’t quite make sense. FMPA would support an alternative that simply stipulates that the PA/TP should study which ever Planning event it feels would be the most prudent based on the specific facility(ies) that could be out of service. Many entities do not run P1 events in stability – rather, they simulate other Planning events that, in their engineering judgment, produce more severe system impacts. Thus it doesn’t make sense to add P1 events just because a major facility could be out of service – this may not change the fact that another event such as a P4 or P5 may still be more important to study due to clearing times, and it doesn’t really save the entity any time.

Likes 0	
Dislikes 0	

Response

John Bee - Exelon - 3

Answer	No
Document Name	

Comment

See Exelon TO Utilities Comments	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
See response to questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

Same explanatory text as Part 2.1.3.

Table 1, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires checking dc batteries for the open circuit condition at least every 18 months. Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly shorter than the PRC-005 maintenance requirement. The PRC-005 standard also requires the checking of dc battery voltage levels every 4 months. Finally, the PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Does the SDT think these timeframes are acceptable?

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

Footnote 14 - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES (P8), than the corresponding SLG fault contingency (P5). And only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

Manitoba Hydro suggests that R1.1.2.2 be revised as suggested above. The P8 event should be moved to extreme events. The other changes are acceptable.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment	
Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.” We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions. **Part 2.4.3 -** We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”. Same explanatory text as Part 2.1.3. **Table 13, Footnote 13** For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement. For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability. **Footnote 14 -** We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	

MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	

NVE proposes the following changes for various requirements listed below:

Table 1, Footnote 13d

NVE recognizes the importance of studying the impact of a failure of a single control circuitry, but has concerns with the duplication of component types in this footnote with other planning events. Studying the failure of control circuitry associated with a breaker trip coil would result in a breaker failing to operate for a fault. This is the same effect as a fault plus a stuck breaker. NVE recommends that Footnote 13d be modified to include studying the failure of auxiliary relays and lockout relays. Footnote 10 should be modified to include scenarios of a failure of a single breaker trip coil to operate.

Table 1, Footnote 13c

Wording to this footnote should be changed to match the portion of the definition of Protection System associated with dc supply to ensure that the failure of any component of a dc supply is studied.

A single station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply) required for Normal Clearing….

R4.2 and R4.5

NVE agrees with the proposed changes to R4.2 and R4.5. Given that the wording and intent of R3.2 and R3.5 is the same as R4.2 anD R4.5, but for different portions of the planning study (steady state vs dynamic), NVE recommends that R3.2 and R3.5 be modified to match R4.2 ans R4.5 to maintain consistency.

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

LADWP doesn not agrtee with the new proposed revisions specifically the new planning event P8 and the changes made to R4.

Likes 0	
Dislikes 0	

Response

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	No
Document Name	

Comment

OG&E recommends that Table 1, Footnote 13(d) should be revised to allow exceptions for trip coil circuit monitoring as follows:

"d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing**, which is not monitored or not reported at a Control Center**.

OG&E suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the Commission's directive from Order No. 754, and is consistent with the recommendations from the Joint Report regarding three phase faults.

Likes 0	

Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
See Question 2 response	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See above comments in Questions 1 & 2.	
Likes 0	
Dislikes 0	
Response	

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned."

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned".

Same explanatory text as Part 2.1.3.

Table 13, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated." Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement.

For 13.d, the wording of "single control circuitry" is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

Footnote 14 - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. "

Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1	
Answer	No

Document Name	
Comment	

Santee Cooper disagrees with the proposed revisions to TPL-001-4. The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation.

Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the efforts of the SDT in revising TPL-001-5 – Transmission System Planning Performance Requirements. BC Hydro votes "No" and wishes to provide the following comment.

The proposed amendments scope from Single Point of Failure is very wide, which will apply to the entire bulk electric system i.e. 100 kV and above. Our ballot would have been affirmative if the scope were limited to extra high voltage (360 kV and above), where a single point of protection failure after a fault can trigger a major system disturbance.

Below extra high voltage levels, BC Hydro protection systems are built using principles of good utility protection practices, as described in the ANSI/IEEE standards and guides, to ensure that they have acceptable reliability i.e. clear faults without mis-operating. Our protection systems are largely redundant but still can have a single point of failure, such as where there is a shared breaker trip coil or a single telecom fibre etc. Based on our fifty years of operating experience, there is no known case where a single point of failure in our high voltage protection system precipitated in a major system disturbance event. It is because probability of a single failure (in our redundant high voltage protection system) impacting our system performance is negligible. Yet demonstrating compliance to the proposed amendments will require BC Hydro to redirect our critical resources (financial and people) in identifying single points of failure in our every single high voltage P&C asset, estimate incremental protection clearing time associated with that failure, and then demonstrate acceptable system performance during the event. Instead of redirecting our critical resources to demonstrate compliance to this negligible probability event, BC Hydro will receive higher reliability benefits by continuing to invest our resources in upgrading the aging protection systems.

Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No

Document Name	
Comment	

Although appreciative of the drafting team's work on TPL-001-5, LES believes the following changes would provide greater clarity within the standard.

R2.1.3 & R2.4.3 – Recommend "when known outages are scheduled" be changed to "when known outages **occur**" to provide greater clarity.

R2.4.3 – The objective for including known outages in TPL-001-5 should be to ensure that all types of known outages are being reviewed while keeping the burden of additional stability analyses within reason. As currently drafted, the standard would require both steady state and stability analyses for all known outages included in the Planning Assessment. LES recommends modifying the standard to allow steady state analyses and limit stability analyses based on the use of Engineering Judgement in the Transmission Planner's technical rationale for selecting known outages. Recommend changing R2.4.3 to state "…under those System peak or Off-Peak conditions when known outages occur **and have been identified as requiring Stability analysis**".

Footnote 13a: To ensure "comparable" isn't mistaken to mean having identical Clearing times, LES suggests revising footnote 13a to instead state "…that provides comparable**, but not necessarily identical,** Normal Clearing times".

Footnote 13c: LES recommends removing "open circuit" from Footnote 13c. The absence of open circuit monitoring is too restrictive to consider a single station DC supply as non-redundant. Both a battery charger and battery provide DC supply redundancy because either device can provide DC power if the other device fails or has an open circuit. Additionally, PRC-005 provides adequate testing for open circuits.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5

Answer	No
Document Name	
Comment	

In the response to Question 1, we voiced our concerns on the inclusion of P8. Rather than its inclusion, one possible alternative would be to redefine the definition of Delayed Fault Clearing to only include backup protection system with an intentional time delay. A separate term could be created for Breaker Failure Fault Clearing. Note that in the NERC technical paper "Protection System Reliability Redundancy of Protection System Elements" by the NERC System Protection and Control Subcommittee dated January 2009, page 13, the committee had to clarify the term for the purpose of their paper. Currently, this white paper is the primary source of guidance for this very complex topic. Due to the expansion of non-redundant components included in the proposed draft of the Standard, the terms provided in the NERC Glossary need to be further developed in order to provide clarity for their new application to this standard.

As stated in previous comment periods, we believe usage of the word "comparable" within footnote 13a is ambiguous. While we are not completely certain, we suspect the SDT means "less than or equal to" when using this word. If so, it would be preferable to instead state "A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides a clearing time less than or equal to Normal Clearing times;"

In both 13b and 13c, using the word "or" within "is not monitored or not reported at a Control Center" may not be consistently interpreted. Any possible confusion might be eliminated by instead using either "not monitored at a Control Center" or "is not monitored *and* not reported at a Control Center" in both 13b and 13c.

Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

CHPD disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new Planning Event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for Extreme Events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

In moving the three-phase fault with protection system failure from an Extreme Event to a P8 Planning Event, the SDT has also changed the required performance levels from that of the Extreme Event to those of the planning standard, which creates an undue burden. Also, while the SDT stated in their Consideration of Comments to TPL-001-5 Draft 2 Question 1 "the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement," the current language of the proposed standard doesn't clearly state that a CAP isn't required. CHPD disagrees with these changes.

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the Joint Report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13. However, CHPD would like to see non-redundant but monitored relays and control circuitry (as defined in Table 1 Footnote 13.a. and 13.d.) have the same exclusion as the monitored communication systems and station dc supplies as allowed in Table 1 Footnote 13.b. and 13.c. for Planning Events P5 and P8.

CHPD suggests the SDT restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This adequately addresses FERC's concern regarding three phase faults from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

Likes 0	
Dislikes 0	

Response

Jeff Landis - Platte River Power Authority - 3

Answer	No
Document Name	

Comment

PRPA supports JEA comments.

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 subrequirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure

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in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

Likes 0	
Dislikes 0	

Response

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Answer	No
Document Name	

Comment

Tri-State does not agree with the language of Footnote 13:

Footnote 13 is weakly worded and suggests that elements of a protection system should be consider rather than shall be studied. Stronger language which clearly defines what components of a protection that are included and what are excluded should be used.

Section D: The standard does not adequately explain the difference between a breaker failing to operating and failure of an element of a protection system resulting in the breaker failing to operate. In most cases, the protection events and post-contingency system states are identical. An addendum or reference to technical documentation which clearly explains the scenarios where they may differ should be included.

Likes 0	
Dislikes 0	

Response

Kelsi Rigby - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment

As stated in response to Question 2 above, AZPS recommends that a definitive time period of "more than 3 months" be added to Requirement 1, Part 1.1.2. Please refer to AZPS's comments in response to Question 2.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
With the exception of clarification for R1.1.2.2 and the P5/P8 suggested change, BPA is in agreement with the other revisions.	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See thw response to Q2.	
Likes 0	
Dislikes 0	
Response	

Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	
We agree with the conforming revisions specifics but we do not agree with additional modifications.	
Likes 0	
Dislikes 0	
Response	

Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No

Document Name	
Comment	

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	
Comment	

The proposed change to requirement R1, part 1.1.2 to eliminate the six month minimum duration requirement for considering known outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 Operational Planning Assessments. Removing the six month threshold also adds a considerable burden on the annual Planning Assessment without providing significant value by requiring studies be performed for short term maintenance outages in the Planning Horizon.

The annual TPL-001-4 Planning Assessments represent projected system conditions in the near-term and long-term planning horizons and are not meant to identify operational concerns for outages shorter than six months. The system models used in the Planning Assessment represent a general snapshot of stressed system conditions with all facilities in-service. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing. In addition, the information regarding planned outages occurring beyond year one of the near-term planning horizon would be expected to be limited or unavailable as most outages are scheduled within two months of the requested outage time. For these reasons, outages shorter than six months are more accurately addressed in the operations planning horizon, when more information is available regarding overlapping outages and current system conditions.

Planned outages are considered in Operational Planning Assessments. T**he IRO-017 standard establishes the outage coordination process** within the operations planning horizon, which covers the period from day-ahead to one year out. The outage coordination process includes development and communication of outage schedules, evaluating impacts and developing operating plans to mitigate outage conflicts, or rescheduling outages when necessary in order to reduce the reliability impact of the critical outage. This process ensures a more accurate modeling of expected system conditions, including information on concurrent outages.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

Table 1, Footnote 13 – The ability to monitor the status of a Protection System Component does not fully mitigate the risk of the failure of a non-redundant component. The exception of 13b is not consistent with the requirements for redundancy in protective relays, even though the components can be very similar in design and performance.

For 13.b, consider removing the qualification, “which is not monitored or reported within 24 hours at a Control Center”. If the SDT believes the qualifications for monitoring and reporting are valid for the communication channel for a communications based relay scheme and elects to leave this, then ITC would only then suggest to add the same “which is not monitored or reported within 24 hours at a Control Center” qualification to 13.a . ITC, however, believes the better wording for the standard is to not have this gualification in either 13.a or 13.b.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	

We do however propose the following improvements :

- Requirement 2.5 addresses “material generation additions or changes”. These additions or changes should already have been included in the model as per (renumbered) R1.1.3. Thus 2.5 is superfluous. However if SDT retains this requirement, it should also address other material additions or changes such as load increase or relocation.
- Requirement 2.7.1: Examples should not be in a requirement, they should be moved to guidance.

- Replace « assessment » in requirements 3.3.1.1 and 4.3.1.2 with « Planning Assessment »

Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Requirement 2.4.3 has been added to TPL-004-4, which caused the Requirement previously identified as 2.4.3 to be renumbered to 2.4.4. Therefore, in the second to last sentence where a reference is made to Requirement 2.4.3, the reference needs to be changed to 2.4.4.	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
While OUC agrees with the addition of P8, OUC believes clarity needs to be added to Requirement 1 in order to avoid the TPL-001-5 standard overlapping with Operations Planning, and believes an outage duration would be an appropriate way to filter outages of less significance that Operations Planning would otherwise be assessing day-to-day.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

We generally agree with the changes, except for R1.1.2.1 as noted above. Also, Is there a need to consider a three-phase fault on a shunt device with a stuck breaker resulting in Delayed Fault Clearing? (See Table 1 Stability Extreme Events) It appears this item is missing.	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
The following questions/requests were previously submitted; however, Tacoma Power is not clear about the drafting team's responses. 1. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team’s intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6. 2. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
We can agree with the changes, notwithstanding our response regarding Requirement 1, Part 1.1.2. The standard drafting team should revisit Requirement 1, Part 1.1.2.1. if the ballot does not pass.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	

It is recommended that for P5 and P8 events in Table 1, the Drafting Team consider modifying the phrase “Fault plus non-redundant component of a Protection System failure to operate” to “Fault plus single component of a Protection System failure to operate” and modifying the phrase “Delayed Fault Clearing due to the failure of a non-redundant relay component of a Protection System protecting the Faulted element to operate as designed” to “Delayed Fault Clearing due to the failure of a single component of a Protection System protecting the Faulted element to operate as designed”. Similarly, note 13 in Table 1 might be modified to read “For purposes of this standard, failure of a single component of a Protection System is considered to be as follows”. It is suggested that this language might describe the same event a bit clearer, and in a way consistent with the description of similar failure for RAS as described in PRC-012-2. This would avoid any potential debate over the definition of redundancy - in order to determine what is a “non-redundant” component, one needs to define what does and does not constitute redundancy in this context (e.g., What about a backup relay that performs similar functions, but is not exactly the same? What about a duplicate relay with slightly different settings, or configured in the system in such a way that it responds a little slower? What if there is a “redundant” trip coil in a breaker, but it’s not hooked up?). It would also clarify that for the case of multiple non-redundant components in a particular Protection Scheme, that the simultaneous failure of all non-redundant components is required to be considered (we assume the intent in such a case would be to consider failure of each non-redundant component one at a time).

As provided in previous comments periods, Exelon recommends removing communication systems from footnote 13 in the revised standard. The SPCS concluded that the analysis of communications systems with regard to single points of failure did not pose enough of a risk for inclusion in footnote 13. As noted in the “Consideration of Comments”, the SDT “augmented the SAMS/SPCS recommendations to include the reference to the subset of communications systems that are part of a communication-aided Protection System”. By doing this, the inclusion of communications systems extends beyond the scope of the SAR to “[c]onsider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report.”

Requirement R2.7 should be revised to reference Requirement R2, Parts 2.1.4 and 2.4.4 and not Requirement R2, Part 2.4.3 based upon the currently proposed draft. Requirement 2.4.4 is specific to the sensitivity studies.

The SDT should consider aligning the language in Requirements R3, Part 3.5 and R4, Part 4.2: “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.”

Likes 0	
Dislikes 0	
Response	

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to #4.	
Likes 0	
Dislikes 0	
Response	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754. **Suggestion**: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	

Comment	
These are not cost effective because it will create additioanl studies that will have minimal to no benefit for planning purposes.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA feels that it is not cost effective to plan and construct a project for a planned outage of short duration that would be coordinated ahead of time according to outage planning processes (development of an operating plan) and would not be planned during peak seasons. It would also not be cost effective to plan and construct a project for a planned outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes.	
Likes 0	
Dislikes 0	
Response	

Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS notes that it believes that, with the exception of Requirement 1, Part 1.1.2, the proposed TPL-001-4 is cost effective. As stated in response to Question 2 above, AZPS recommends that a definitive time period of “more than 3 months” be added to Requirement 1, Part 1.1.2. The inclusion of outages that are 3 months or less creates unnecessary study burden with little or no added reliability benefit and the currently proposed criteria increases the potential for inconsistency relative to planning assessments, which inconsistency increases costs while eroding the overall reliability benefit anticipated. Please refer to AZPS’s response to Question 2 for additional details.	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	No
Document Name	
Comment	

Absolutely NOT. The SDT has not presented a solid cost effective analysis on the proposed changes leaving industry seriously questioning the process and the amount of work that would be potentially created by these changes and the minimal return on investment.

ADDITIONAL COMMENTS

1. In reviewing the edits to R1.1.2, I'm still concerned about the vagueness of those outages that must be modeled and whether such consultation will now require the RC to meet with each TP and PC separately within the FRCC on an annual basis.

2. Given the changes to requirement R1.1.2, we believe there needs to be applicability in the standard to the Reliability Coordinator and not just the PC and TP. Also, since the SDT struck out the duration of six months in R1.1.2, there should be a time-frame around the length of transmission outages given some outages are only for a few hours, some for a day, a week, a month, etc., that may not be covering the year, season, or load level entities are assessing.

(3) Regarding the edits to R1.1.2, what happens if the RC, TP, or PC disagree as to which outages to include in the System models? Is it acceptable to the SDT if procedures are written whereby not all entities are in agreement with which outages to include?

(4) In R2.1.5, the SDT changed "studied" to "assessed". Can the SDT provide background on what is now expected with the term "assessed" differently than what was performed under the term "studied"?

(5) In R2.4.5, can the SDT elaborate on what is expected in, and how detailed, an entity's spare equipment strategy should be that is needed for TPL-001-5?

(6) In R2.4.5, the wording "The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment" opens entities up to major compliance interpretation issues as it's not certain that entities will evaluate ALL conditions that the System is expected to experience in our Planning Assessment, this needs to be further clarified by the SDT.

(7) P5, and footnote 13, was modified to cover non-redundant components of a Protection System. This is a substantial additional burden onto entities. Seminole requests the team to perform a cost effectiveness study concerning these additional edits.

(8) In the Cost effectiveness Document updated(3/8/2018), pg 3 Footnote 13-(2 single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), How is this not a single point of failure?

Likes 0	
Dislikes 0	
Response	

Jeff Landis - Platte River Power Authority - 3

Answer	No
Document Name	
Comment	

PRPA supports JEA comments.

Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

Likes 0	
Dislikes 0	

Response

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD

Answer	No
Document Name	

Comment

The P8 event creates a major burden to entities to mitigate Extreme Events. This is not cost effective due to the rarity of events and the added reliability benefit is marginal compared to the cost, logistics, coordination and the aggressive implementation schedule needed to achieve the desired outcome.

Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. CHPD is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, CHPD recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

Likes 0	
Dislikes 0	

Response

Fred Frederick - Southern Indiana Gas and Electric Co. - 3

Answer	No

Document Name	
Comment	

The proposed revision is potentially not cost effective depending on the clarification requested in question 4. We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	

The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation.

Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and

regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
NIPSCO agrees with JEA comments	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which is not required by Order No. 754. Because P8 events are	

considered to be rare occurences in the industry, requiring a CAP is not a effective use of resources. The following conclusion statement in the Joint Report on Order 754 supports this position: “This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5.” *See Order 754 Assessment at p. 11.*

Likes 0	
Dislikes 0	

Response

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

LADWP does not agree with majority of the change. There is no evidence that the changes will be more cost effective. Unitl the new proposed is agreed and approved, it would be hard to made a comment on this question.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

Please see JEA's comments.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

MEC supports NSRF comments. In addition, the zero defect compliance work to maintain perfect protection system drawings and change management is significant with little additional actual system reliability gain due to the rare probability of a delayed cleared fault combined with a single-point-of-failure protection component failure that isn't already known. NERC and industry should work together to seek a better risk based strategy to focus on important substations. Examples could be the use of voltage class levels similar to FAC-003 (200kV and above or as identified by the RC / PA), high fault current levels similar to PRC-002, or number of transmission interconnections similar to the FERC Order 754 effort.

Likes 0	
Dislikes 0	

Response

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment
Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry. If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	

Comment
The changes are forcing the industry to invest to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP/PC to decide whether mitigating possible Casading is cost effective.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	No
Document Name	

Comment

No, Although the drafting team has identified "adding redundant protection improves the relialbity of the Bulk Power System at lower costs than other contructions projects" there exists significant costs for associated component of the protections system.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

Likes 0	
Dislikes 0	

Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

1. The required analysis of all scheduled outages in the near term horizon is not cost-effective, as it will result in many studies being run without meaningful results and/or with time spent "proving the negative".

2. Introducing a new type of event in Planning Event P8 creates unnecessary compliance burden and is illogical. Furthermore, it opens up industry to additional illogical changes to a planning standard that was generally working pretty well before these changes.

3. Flatly requiring P1/P2 events be studied in stability is likely to simply create busy work since an entity may (not a guarantee – based on details specific to each facility and engineering judgment) determine that a P4 or P5 is more appropriate to simulate, but would be required to run the P1 or P2 event regardless (e.g. in addition to those events the entity feels are best to study).

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a "non-redundant control circuitry" requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

See comments from MRO NSRF.

Likes 0	
Dislikes 0	

Response

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski

Answer	No
Document Name	

Comment

GRE agrees with the MRO NSRF and ACES comments.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

To determine if something is cost-effective, the analysis must consider alternatives to achieve a measurable outcome.

The FERC directives are narrowly drafted without significant alternatives to fulfill their outcomes. Reflected in the proposed revisions and Implementation Plan are the directives' narrow framework and, as such, a meaningful analysis of the revisions and Plan's cost-effectiveness is indeterminable.

Likes 0	
Dislikes 0	

Response

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	

Comment

Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. We do not disagree with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, Rrecommend NERC survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.

Likes 0	

Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
The proposed revisions to this Standard would add significant resource and financial burden to TOs and GOs. Recommend for the SDT to evaluate System performance issues thru planning studies prior to making Corrective Action Plans (CAPs) mandatory in the Implementation Plan. This would provide time for the SDT to evaluate the impact and cost implications that these new Requirements have on industry. After an evaluation is done, then the SDT can determine what CAPs would be required and reduce the financial impacts to industry by utilizing a separate Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SCE submitted comments regarding the cost-effectiveness of the proposed revisions to TPL-001-4 during a previous period. SCE's opinion has not changed and, consequently, SCE would like to reiterate our feedback from the previous comment period (i.e., the comment period ending 10/23/2017).	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe a more cost effective way approach to meeting the FERC directives exists. The proposed changes should allow registered entities the flexibility to determine how they will address this BES reliability risk. The currently proposed solution requires a registered entity to conduct a duplicative contingency analysis for a three-phase fault that is less likely to occur than a single-phase-to-ground fault under similar conditions.	

2. The “dc supply” reference to open circuit within Footnote 13c could require an entity to purchase additional equipment based on the accepted configuration. We recommend revising the footnote to only consider when the dc supply is not monitoring or reporting abnormal DC voltages.
3. We thank you for this opportunity to comment.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which are rare occurences in the industry and not required by Order No. 754.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

City Light supports JEA comments.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

As proposed, the revisions are overly-complicated and will require a considerable amount of additional work for defining, modeling, and analyzing new contingencies. Further, if corrective actions are required for the proposed P8 event, there is little real payback due to the extreme unlikelihood of the event.

Likes 0	
Dislikes 0	
Response	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer	No
Document Name	
Comment	

There is some correlation between FERC directives in Order NO. 786 and Order No. 754 such as a Tranmission Planner assessing their portion of the Bulk Electric System (BES) for locations at which a three [illegible] accompanied by a protection system failure could result in a potential reliability risk (Order No. 754) and the expansion on Protection System Failures versus Relay Failures (Order No. 786). However, EEI summarized it best by stating in Order No. 786 (p. 46), "...expanding planning studies to include all manner of protection system failures could create a scenario where planners would have to conduct unlimited and unbound studies."

The potential for unlimited studies to include all manner of protection system failures is not a cost effective way of meeting both FERC directives. This new revision expands the purview from relay failure to failure of all protection system components. Additionally, this requirement (and its predecessor) required assessments of entire system unlike the limited ones per FERC order 754.

Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	

See comments in response to question 2. The development of a contingency set with acceptable system adjustments would be more efficient than requiring seperate cases be developed.

Likes 0	
Dislikes 0	
Response	

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
OUC would recommend providing some guidelines in order to guide the discussion on how to solve issues found under new Planning Event 8, such as recommending Zone 2 or Zone 3 protection where applicable (if acceptable though testing) or the addition of dual and separate DC sources. Guidelines on what actions to take and when to take them (along with cooridinating these upgrades with the company's protection group) would help further keep the revisions cost-effective by providing a methodology of least cost options to higher cost options.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Yes if the clarification to Requirement 1, Part 1.1.2 is made	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
While the proposed revisions to TPL-001-4 along with the Implementation Plan may be a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754 in terms of corrective action plans, the proposed revisions will present a very significant burden on Planning and Engineering staffs to investigate and identify "non-redundant" components of a Protection System. This incremental burden will have adverse cost impacts.	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Michael Jones - National Grid USA - 1, Group Name National Grid

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	

No comment or opinion on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
No response or comments.	

Likes 0	
Dislikes 0	
Response	

Comments received from APPA

Questions

1. Do you agree with the creation of the proposed P8 event?

☐ Yes
x☐ No

Comments: APPA concurs with the JEA comments that the addition of the P8 event is beyond what was in the Standards Authorization Request (SAR).

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

y☐ Yes
☐ No

Comments:

3. Do you agree with the proposed implementation plan?

☐ Yes
x☐ No

Comments: APPA believes the 36 month period for the proposed standard to be effective is appropriate as is the 24 month period for development of the CAP. However, we do endorse the overall implementation plan and support the reasoning for that lack of support provided in JEA's comments. Similarly, we support the JEA suggestion to remove the proposed P8 event and its associated CAP and seek industry feedback on a more feasible implementation plan.

4. Do you agree with the proposed revisions to TPL-001-4?

☐ Yes
x☐ No

Comments: APPA believes that the proposed revisions to TPL-001-4, especially the inclusion of P8 is not workable and supports the JEA comments and suggestions.

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

   ☐ Yes
   x☐ No

   Comments: APPA believes the proposed revisions and implementation plan will not result in a cost effective way to meet the FERC directives in Order No. 786 and Order No. 754. The inclusion of event P8 is the driver for increasing the costs of the proposed standard. Importantly, the increased costs are not commensurate with a material improvement in reliability.

   Public power endorses the JEA comments and suggestions.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name: 2015-10 Single Points of Failure | TPL-001-5

Comment Period Start Date: 2/23/2018

Comment Period End Date: 4/23/2018

Associated Ballot: 2015-10 Single Points of Failure TPL-001-5 AB 2 ST
2015-10 Single Points of Failure TPL-001-5 Implementation Plan IN 1 ST

There were 70 sets of responses, including comments from approximately 190 different people from approximately 117 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **Do you agree with the creation of the proposed P8 event?**

2. **Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?**

3. **Do you agree with the proposed implementation plan?**

4. **Do you agree with the proposed revisions to TPL-001-4?**

5. **Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?**

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Paul Henderson	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Shari Heino	Brazos Electric Power	1,5	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Exelon	Chris Scanlon	1		Exelon Utilities	Chris Scanlon	BGE, ComEd, PECO TO's	1	RF
					John Bee	BGE, ComEd, PECO LSE's	3	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Haley Sousa	5		Chelan PUD	Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
					Joyce Gundry	Public Utility District No. 1	3	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						of Chelan County		
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
DTE Energy - Detroit Edison Company	Jeffrey DePriest	3,4,5		DTE Electric	Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Daniel Herring	DTE Energy - Detroit Edison Company	4	RF
JEA	Joe McClung	3,5	FRCC	JEA Voters	Ted Hobson	JEA	1	FRCC
					Garry Baker	JEA	3	FRCC
					John Babik	JEA	5	FRCC
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
National Grid USA	Michael Jones	1		National Grid	Michael Jones	National Grid USA	1	NPCC
					Brian Shanahan	National Grid USA	3	NPCC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Company Services, Inc.					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5		BC Hydro	Patricia Robertson	BC Hydro and Power Authority	1	WECC
					Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	2	WECC
					Pat G. Harrington	BC Hydro and Power Authority	3	WECC
					Clement Ma	BC Hydro and Power Authority	5	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Eversource Energy	Quintin Lee	1		Eversource Group	Timothy Reyher	Eversource Energy	5	NPCC
					Mark Kenny	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Hydro One, NYISO and Eversource	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State	7	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Reliability Council		
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						System Operator		
Scott Miller	Scott Miller		SERC	MEAG Power	Roger Brand	MEAG Power	3	SERC
					David Weekley	MEAG Power	1	SERC
					Steven Grego	MEAG Power	5	SERC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Amy Casuscelli	Xcel Energy	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Kiet Nguyen	Grand River Damn Authority	1	SPP RE
					louis Guidry	Cleco	1,3,5,6	SPP RE
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma Gas and Electric Co.	6	SPP RE
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	SPP RE
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	SPP RE
					John Rhea	OGE Energy - Oklahoma Gas	5	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						and Electric Co.		

General Summary

The SDT appreciates the comments submitted. Overwhelmingly, the industry response to the proposed Table 1 P8 Event was negative. The SDT considered the weight of the industry responses rejecting the proposed addition to the Planning Events and has removed it from the draft TPL-001-5 Reliability Standard.

The SDT believes it is important to reiterate that the industry has been aware of concerns about Protection System component single point-of-failure (SPF) and corresponding risks to the BES since as early as the 30 March 2009 NERC Alert. Further, it was clear from the SPCS and SAMS report, following the data collection and assessment in support of FERC Order No. 754, that SPF reliability concerns were substantiated. The draft TPL-001-5 language proposed by the SDT was consistent with how other identified risks to reliability are incorporated into the Transmission System Planning standard, including similar assessments of low probability events (e.g., breaker failure).

A SPF in a Protection System is a wholly-preventable risk to the BES. Likewise, existing Protection System designs, as well as future ones can be made to assure that SPF is not a concern. Faults, conversely, are and will remain an inherent risk to the Transmission System. The SDT believes that single line-to-ground (SLG) fault migration into a three-phase (3ph) fault is a very real phenomenon, especially considering the Delayed Clearing of the initiating fault that may arise due to a SPF in a Protection System. In other words, today it is not only probable but certain that portions of the BES protected by Protection System with SPF will experience, when a SLG fault initiates, the evolution of a SLG-to-3ph fault, given significant durations before backup protection initiates.

The locations of SPF can be identified, simulated under faulted conditions, assessed for impacts to System performance, and solutions identified; each of which the planning entities can play a meaningful role in achieving. The SDT evaluated numerous alternatives and ultimately proposed to industry multiple options for TPL-001-5 to elevate the Contingency event that represents a 3ph fault plus a failure of a non-redundant component of a Protection System:

1. Maintain 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events, but require Corrective Action Plan (CAP) when Cascading identified.
   [TPL-001-5 Draft #1, Industry Comment period: 04/25/17 - 05/24/17]

2. Maintain 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events; do not require a CAP, but do require stricter actions than typical Extreme Events when Cascading identified.
   [TPL-001-5 Draft #2, Industry Comment period: 09/08/17 - 10/23/17]

3. Move 3ph fault + SPF in Protection System event to Table 1 Steady State & Stability Performance Planning Events as P8 Event; require a CAP, but maintain the System performance requirement as Cascading.
   [TPL-001-5 Draft #3, Industry Comment period: 02/23/18 - 04/23/18]

Each of these options were rejected by industry, despite the SDT attempts to convey the reliability concept that SPF in a Protection System is preventable and to emphasize that the severity of an event's impact must temper the tendency to diminish its importance because it is perceived to be unlikely. The SDT has, therefore, made no change to the existing evaluation of 3ph fault in the Table 1 Stability Performance Extreme Events, except to separate breaker failure from the SPF in Protection System event.

1. ***Do you agree with the creation of the proposed P8 event?***	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called "Joint Report").

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, **Chapter 2 – Alternatives**, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "**Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event**". The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, **Chapter 3 – Conclusion**, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event. Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5. **Suggestion**: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	

NextEra does not support P8 events being considered as planning events instead of extreme events. A 3PH fault plus protection system failure is a very low probability event.Ne	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
For the HV BES level, both Categories P5 and the new P8 events require the same performance for both a SLG fault and a 3-Phase fault. BPA believes the performance for the existing P5 is more conservative and the P8 Category is not required for the HV BES level. In addition, BPA suggests deleting the new P8 and modifying P5 to include a row for 3Ø (three phase) for the EHV BES level only allowing interruption of firm transmission service and non-consequential load loss.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	

Adding P8 changes a an EXTREME contingency to a CREDABLE contingency. A 3 phase fault with delayed clearing was an extreme event under category D on Table 1 of the original TPL standards. This contingency has always been an extreme contingency. The question not being addressed is, "what reliability improvement can be accomplished by adding P8?". If P8 studies show instability, there is no requirement for a corrective action plan. Keeping in mind that this is a required standard, why create a P8 contingency, which will increase the work load and cause additional distractions, when the results don't matter?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Seminole is in agreement with the comments submitted by JEA but would like to provide additional comments relating to the proposed P8 Event. In reviewing the Cost Effectiveness document, the Technical Rationale, the SPCS/SAMS Order 754 Report, and the proposed redline to the existing TPL-001 Reliability Standard, Seminole does not believe that the proposed P8 Planning Event is prudent and the technical rationale is flawed in light of what the SPCS/SAMS documented in their review of the Order 754 Data Request analysis. As documented by JEA, the SPCS/SAMS never recommended making a three-phase fault with a single point of failure a Planning Event unless it included its own performance criteria. Additionally, the SDT and the SPCS/SAMS clearly recognize that a three-phase fault is in and of itself an event that has a low probability of occurrence, and adding a low probabilistic single point of failure of a protection system on top and requiring that this be analyzed as a Planning Event is beyond prudent planning and results in diminishing returns from an analysis and cost effectiveness standpoint. The SDT also made a gross assumption in regards to the amount of work required to evaluate these events by stating that the P8 Planning Event does not require steady state evaluation and "ONLY" requires stability analysis as to insinuate that the level of work is somehow lessened by making this statement.	

The cost effectiveness document falls short of providing any substantive cost effectiveness in regards to the additional analysis that would be required by the addition of Planning Event P8 Suggestion: The existing Extreme Event within Table 1, 2f., allows for the Transmission Planner to use operating experience to develop a contingency event that would result in a wide-area disturbance, such a disturbance that one could presume would cause Cascading, voltage instability or uncontrolled islanding. Operating experience would bring one to the conclusion that the proposed P8 Planning Event is in fact a low probabilistic event and should NOT be considered a Planning Event but rather an Extreme event that is already part of the Extreme Event Table within Table 1	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Jeff Landis - Platte River Power Authority - 3	
Answer	No
Document Name	
Comment	
PRPA supports JEA comments. JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called "Joint Report"). However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report	

listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, Chapter 2 – Alternatives, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event". The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, Chapter 3 – Conclusion, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from

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draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP does not agree with the creation and inclusion of P8 for the following reasons:

1. We see nothing within the project's final SAR which would accommodate the addition of a completely new Performance Planning Event in Table 1. As a result, we believe its proposed inclusion goes beyond the scope of the SAR.

2. The creation of P8 introduces an inconsistent treatment of breaker failure. A 3-phase fault with the failure of a non-redundant component of a Protection System (footnote 13.d, such as the failure of single-control circuitry that would prevent tripping but initiate breaker failure) that results in a breaker failure operation is considered a Planning Event in P8. However, the same 3-Phase fault with a stuck breaker is included under Extreme events in the Stability column and results *in the exact same event*. If a 3-phase fault results in a breaker failure operation, what is the reliability benefit of differentiating the cause between a Protection System component failure or a stuck breaker? While AEP disagrees with many aspects of the recently-proposed revisions, the concerns expressed in this paragraph are the primary drivers behind our decision to vote negative during this comment/ballot period.

3. AEP is concerned that the inclusion of P8, coupled with its indistinct relationship to P5, will lead to inconsistent decision-making when using and applying Table 1. This was well illustrated during the March 22nd webinar by both the questions posed and the responses and insight provided by Chris Colson. A number of possible scenarios were provided by remote attendees seeking insight how the table should be correctly applied in those cases. At times, Mr. Colson expressed appreciation for the thought process, reasoning, and "logical analysis" used by those who were posing the questions and referencing Table 1. Our own impressive was different however, as we believe referencing the Table in such a "nonlinear" or "cyclical" way would actually lead to inconstant interpretation and application of the table. As a result, we believe it is possible (and perhaps even likely) that the table will not be consistently applied.

In our response to Question #4, AEP has provided possible alternatives to P8's inclusion for the drafting team to consider.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Santee Cooper supports JEA's comments on this standard. No, the addition of the P8 event in Table 1 goes beyond what is required by the SAR. The Joint Report cited that the probability of a three-phase fault with protection system failure is low enough that it does not warrant a planning event. The creation of the P8 event is not warranted and should be removed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as	

Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses. If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
I support comments submitted by the MRO NERC Standards Review Forum	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

NIPSCO agrees with JEA's comments.

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called "Joint Report").

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, ***Chapter 2 – Alternatives****, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "****Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event****". The creation of the proposed P8 event in this version has clearly overlooked this fact.*

The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion****, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.*

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5. ***Suggestion**: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the* Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	No
Document Name	
Comment	
OG&E considers the proposal to categorize the P8 event as a Planning Event as being in conflict with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its "Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" white paper ("Joint Report"). The SPCS and SAMS advised that three-phase fault Single Point of Failure events should remain categorized as Extreme Events and that "[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event." *See* Order 754 Assessment at pp. 9 and 11. Recommendation: Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	

The roposed addition of the P8 in Table 1 is beyond the standard requirements. the possiblity of this event occuring is very remote. Requirement R4.3 (the deleted portion) should be kept in the standard. The proposed changes does not address any current issues or concerns based on the past history. the changes on the remedia; actopm scheme seems to be appropriate.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
Given the similarities between P5 and P8 events, NVE recommends that the proposed P8 events should replace the existing P5 events. It is expected that in most portions of the BES, there will be few, or no, SLG contingencies that would result in more severe impacts than the corresponding 3 phase fault contingencies with a failed non-redudant component of a Protection System. A Footnote 14 can be added to the Fault Type that allows the Transmission Planner or Planning Coordinator to change the fault type from 3 Phase to L-G based on the failure of the non-redundant component of a Protection System being studied (i.e. a SLG fault for a failure of a single phase electromechanical relay) or based on the impact to the system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

P5 events already covers the concern of failure of non-redundant protection systems with a single line to ground fault. The majority of multiple contingency events in TPL-001 only require analysis of a more frequent single line to ground fault. By including the P8 event, development of a corrective action plan may be required for a very low probability event (3-phase fault plus failure of a protection system). Ideally the drafting team should attempt to calculate probabilities and keep the single and multiple contingency categories within roughly a one in thirty year probability of occurring. All other less frequent events should be considered extreme and it should be up to the discretion of the Transmission Planner/Planning Coordinator whether investment is warranted. If 3-phase faults are assumed to have a 1 in 10 year frequency and protection failure a 1 in 10 year frequency then a 3 –phase fault with protection failure has a 1 in 100 year frequency. Single phase faults have a higher probability of 1 in 1 year to 1 in 3 year depending on the voltage level. Protection failure with a single phase fault is closer to 1 in 30 years.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino

Answer	No
Document Name	

Comment
By creating the new "P8" single-point-of-failure category of events and by requiring a Corrective Action Plan (CAP) when such P8 events cause cascading or uncontrolled islanding, the Standard Drafting Team has clearly gone beyond the recommendation in the Standard Authorization Request (SAR). The SAR only recommends that the TPL-001-4 standard be revised "so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection system." It does not recommend or

require that these new P8 events, which are extreme events, be held to a higher standard than thaFlppst of the other extreme events with a new event category unto itself. It also does not recommend or require that such events be mitigated with a CAP, a requirement that is not applied to any of the other extreme events. These P8 events are extreme events and should be held to the same criteria that is applied to the other extreme events. SMUD supports the SAR recommendation to include single-point-of-failure events in its annual assessment of extreme events. SMUD does not, however, support the hard requirement to mitigate such events when studies indicate they may lead to cascading or uncontrolled islanding and prefers instead to leave the decision to mitigate such events to the Planning Coordinator and Transmission Planner just as such discretion exists for all other extreme events. However, by including the P8 event in Table 1, it inappropriately and erroneously subjects the category P8, extreme events, to Requirement 2.7 that requires a CAP when performance requirements are not met, effectively exceeding the concepts included in the SAR. The P8 events is an extreme event and needs to be held to the same requirements as applied to other extreme events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and	

impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses. If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy disagrees with the creation of the proposed P8 as a Planning Event. The proposed addition of the P8 event goes beyond of what is required in the Standards Authorization Request (SAR). The joint report by the SPCS and SAMS subcommittees considered the events (similar to the proposed P8) to be 'elevated to a planning event with its own system performance criteria' (Chapter 2 –	

Alternatives of the Joint-report) as one of the alternatives, however, the joint report did NOT recommend this alternative citing the fact that "Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event". The probability of this event occurring is low, and the change of "relay" to "components of a Protection System" with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint-report. The implementation of the proposed P8 event is NOT needed and should be removed. We believe that Requirement 4 sub-requirement 4.2 together with clarified P5 (Table 1), modified extreme events – stability 2e-2h (Table 1), and the clarified Footnote 13 will adequately address the Commission's concerns.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	No
Document Name	
Comment	
Neither the SAR, FERC Orders, or the SPCS/SAMS report appear to require or explicitly recommend the creation of a new planning event type in order to address single-point-of failure. Based on the data reported in NERC's analysis of the Order 754 Data Request, the conclusion can be drawn that the majority of scenarios which will need to be analyzed under the P8 event will consist of lower voltage facilities which are less likely to create an "adverse system impact" as compared to higher voltage facilities that are more likely to have fully redundant protection systems. Such events are already included under the existing category of "extreme events" – a more efficient way to address the risks of critical SPF scenarios (as well as other critical vulnerabilities that might exist) might be to direct the TP or PC to develop a more defined process to screen extreme events, identify those which pose the greatest risk, and to determine those that may be appropriate to study and possibly mitigate.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
See Exelon TO Utilities Comments	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	FMPA_2015-10_Unofficial_Comment_Form_2018423_2_.docx
Comment	
FMPA disagrees for the following reasons.	

1. The revisions exceed the properly and dutifully developed scope of the SAR, and do so without any substantiated basis (e.g. there is no "new evidence" to suggest the scope of the SAR should have been exceeded). Creating a Planning level event was a specific option considered by the NERC System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling subcommittee (SAMS) in their joint report, referenced in the Technical Rationale for this Project. The purpose of the SAMS/SPCS joint report was to evaluate the available data and make a recommendation as to the level of reliability risk that did, or did not, exist, and recommend paths forward to address those risks. Industry provided the data for the Section 1600 data request dutifully and faithfully entrusting SPCS and SAMS to carefully anyalze that data and make reasonable recommendations to industry, NERC and FERC based on the evidence. This is what SPCS and SAMS did. The joint report concluded a Planning level event was not warranted and made recommendations to ensure that Protection system failures with three phase faults were studied as extreme events.

2. Elevating an event to a Planning event when data does not suggest this is warranted creates complexity and confusion and puts other events at risk of the same fate and changes aspects of the planning standard that were working well and did not need to be changed. The joint report concluded there was a reliability risk. FMPA agrees with this. The joint report recommended modifying the extreme events and footnote 13 in the TPL-001-4 standard. Again, FMPA agrees with this approach – it makes sense given the data that industry provided in the Section 1600 data request. Effectively, a protection system failure with a three phase fault represents the same reliability risk as a breaker failure event with a three phase fault, which is already studied as an extreme event. This grouping was already contemplated in the prior revision of TPL-001-4; it was the over-simplification of the description of protection systems in the footnotes and lack of explicit statements in the extreme events list in Table 1 that created the reliability gap. The end result of creating a Planning level event for Protection System failures would be to send the message that the other three phase fault extreme events which are statistically equivalent to them should also be studied as planning events.

3. FMPA disagrees with the Technical Rationale on three points and therefore does not agree that introduction of this P8 event is justified or warranted:

A. The Technical Rationale for this Project makes the argument that the reason a Planning Event is warranted is the mere fact that the joint report exists – a report which concluded the exact opposite. This makes no sense, and serves to undermine all the work industry, SPCS, and SAMS did in investigating the reliability risks and determining a path forward to address those risks.

B. The Technical Rationale's assertion that elevating protection system failures to a Planning Event is not significant since CAPs are only required if there is a risk of Cascading or or widespread electric service disruption doesn't make sense, since industry has previously, and through much development and debate, established the clear line that Planning events are based on more rigorous performance criteria than this. Hence, an event that is only required to be remedied if it causes Cascading or widespread electric service disruption (but not other performance criteria violations) is not a Planning Event and doing so only creates confusion in the standard where previously there was clarity.

C. FMPA also feels it is poor justification to claim that the prior round of industry comments requested the creation of this Planning event. The prior industry comments were solely a reaction to the confusion that was introduced into the standard when the SDT attempted to exceed the scope of the SAR by creating a quasi-third performance category. The result of this was industry felt forced to pick sides. FMPA does not believe any entity in industry, not one single commenter, would have recommended a Planning event if the original draft that was posted for comment had followed the scope of the SAR and left these events as extreme events where they belong.

FMPA would support doing what was recommended by the SPCS/SAMS joint report and what was written in the SAR for this project, and does not support exceeding the scope of the SAR nor the recommendation of the joint report, which this current proposition does. It is of the utmost importance that we send a message to industry that, when a 1600 data request is prepared and industry is asked to carefully analyze an issue, we will make use of that analysis and value it, and that when we request that changes to standards be based on careful, logical analysis, and that careful, logical analysis is completed, we follow the recommendations of that analysis.

To be very clear: FMPA believes protection system failures should be studied, and FMPA already studies protection system failures in a rigorous fashion.It is quite likely that, should FMPA identify performance issues due to protection system failures in its studies, FMPA and/or its members would upgrade its/their protection systems to address the observed issues. That is, good engineering and planning practices will be followed. However, FMPA believes that any system upgrades or CAPs that are mandated by the standard language should be based on reliability risks; and not just because they are “inexpensive or “easy”.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No

Document Name	
Comment	

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

See comments from MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF and ACES comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Due to possible confusion with interpretation of the new P8 event, we do not fully agree with the implementation of the new event in the Standard.	

The distinction and required performance criteria for the P5 and P8 events should be clarified and specifically documented within the Standard. As presented, Table 1 (Steady State & Stability Performance Planning Events) is difficult to interpret. One method to clarify the table might be to separate out the P8 event within Table 1 (Steady State & Stability Performance Planning Events) and specifically document the steady state and stability performance requirements for P8. For example, it is not clear from the Standard if a Corrective Action Plan is only required if the P8 event results in Cascading. One additional observation for Table 1 (Steady State & Stability Performance Planning Events). Per Table 1, steady state and stability analysis is applicable for the P5 event and the P8 event. The implementation of the P5 event and the P8 event in steady state analysis will likely be identical for both of these events (since fault type usually is not considered). However, • for P5, Non-Consequential Load Loss is not allowed for EHV facilities. • For P8, Non-Consequential Load Loss is allowed for EHV facilities. This is a possible contradiction that should be reviewed and clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	No
Document Name	
Comment	
The proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as	

one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, ***Chapter 2 – Alternatives***, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "***Probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event***". The creation of the proposed P8 event in this version has clearly overlooked this fact. The Joint Report does agree that there is *"the existence of a reliability risk associated with the single points of failure in protection system that warrants further action"* (We agree with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event. Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5. **Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.**

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") does not agree with the creation of the proposed P8 event. A three-phase fault plus delayed fault clearing due to the failure of a non-redundant component of a Protection System in one event is a very rare occurrence in power system disturbances, beyond the scope of a planning event, and therefore should be considered an Extreme Event. As an alternative to the creation of a proposed P8 event, CenterPoint Energy recommends modifying the Extreme Event requirement, as proposed in the approved SAR, to expressly require evaluation of a three-phase fault and Protection System failure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
See comments below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We believe the proposed three-phase analysis is duplicative to Category P5 events that study single-phase-to-ground fault types. While three-phase faults can be more severe, the probability of such events are less likely to occur. This could set a precedence requiring PCs and TPs to include other less likely events in their future studies, or held accountable otherwise. We recommend removing this proposed event from the standard and provide registered entities an opportunity to individually address, on their own and not required through this standard, the concerns to BES reliability raised during the FERC Technical Conference, recommendations from various NERC Technical Subcommittees, and the efforts of this SDT.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group considers the proposal to cateogorize the P8 event as a Planning Event as going beyond the scope of the Federal Energy Regulatory Commission's (FERC) Order No. 754. The FERC order requires that NERC review how single points of failure on protection systems are studied and identify additional actions necessary to address the matter; however, Order 754 does not require a Corrective Action Plan (CAP) to be developed or implemented. *See* Order No. 754 at PP 19-20. By re-categorizing P8 events as a Planning Event, rather than an Extreme Event, the proposed standard would require the TP to prepare a Corrective Action Plan in accordance with Section 2.7 *et seq.* of TPL-001-4. Summarily, the proposed revision presents a requirement not specifically defined by FERC.

Moreover, the proposal to categorize P8 contigencies as Planning Events conflicts with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its Order No. 754 assessment (Joint Report). The SPCS and SAMS advised that P8 events should remain categorized as an Extreme Event and that "[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event." *See* Joint Report at 9 and 11.

Recommendations:

1. Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concerns, recommendations from the Joint Report, and satisfy the objective of the SAR, regarding the single points of failure in Protection Systems.

2. Should the drafting team decide to categorize a P8 contingency as a Planning Event, the drafting team should consider expanding the applicability of the standard to include those functional entities from which the Transmission Planner (TP) must receive system protection data: Generator Owner (GO), Transmission Owner (TO), and Distribution Provider (DP). Because a non-vertically integrated Planning Cooridnator (PC) or TP (e.g., an RTO/ISO) must receive and coordinate system protection data from the GO, TO, and DP in order to satisfy the planning requirements, the standard should be revised to include data submission requirements for the GO ,TO, and DP. The proposed standard's reliance on MOD-032 as a means to receive system protection data is insufficient because MOD-032 does not specifically require such data be provided to the TP.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
We support JEA comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No

Document Name	
Comment	
The focus of the contingencies must be on the likelihood of them happening. P8 contingencies consist of a three-phase fault plus non-redundant component of a protection system failure to operate. Oncor's transmission system experiences very low instances of three-phase faults as compared to single-phase faults. In addition, a three-phase fault with non-redundant component of a protection system failure to operate is even more rare. The likelihood or probability of a P8 contingency occurring is so low that Oncor believes it would not be practical both from an engineering and economical standpoint to elevate this event to a P level contingency. It better fits in the extreme event category.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
If the fix for a cascading three-phase fault with delayed clearing event is the installation of a redundant system protection component, we thoroughly support such a change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We agree with the creation of the proposed P8 event. However, in our view, following a P8 event the tripping of a circuit due to a generator pulling out of synchronism should be permissible as long as it doesn't result in cascading or uncontrolled separation. The proposed standard requires that for the P8 planning event, "The System Shall remain stable" and "Cascading and uncontrolled islanding shall not occur". However, since, there isn't a common understanding of what the system remaining stable means, we suggest including the following sub-requirement in the standard for additional clarity:	

4.1.4. For planning events P8: When a generator pulls out of synchronism in the simulations, the resulting apparent impendace swings shall not result in Cascading. Alternatively, a similar clarification as our proposed sub-requirement 4.1.4 can be added to Condition (a) on top of Table 1 as follows: **a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.**	
Likes 1	Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;
Dislikes 0	
Response	
Thank you for your comments.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the addition of the P8 event. If the occurrence of a P8 event violates the performance requirements of Table 1, even after Interruption of Firm Transmission Service and Non-Consequential Load Loss, then corrective actions are warranted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes

Document Name	
Comment	
ITC agrees with the SDT that the creation of a P8 event is appropriate to build CAP to prevent the system from cascading when a SLG fault propagates into a 3-phase fault.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with the creation of the proposed P8 event. Texas RE recommends including Item J in Table 1 in the Steady State & Stability (P0 through P8 events) list as stability issues can be associated with voltage.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Yes. We agree with adding the proposed P8 event with the understanding that Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, then if needed, the corresponding SLG fault contingency. More specifically, the need to simulate a subsequent SLG fault of the corresponding contingency would be only if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. It is also expected that there will be "extremely few," or more likely "no", SLG fault contingencies that would result in more severe impacts than the corresponding 3-phase fault contingencies. Please see comment for Footnote 14 in the responses to Question 4. It is difficult to ascertain the simulation performance requirement for P8 events. To help clarify these performance requirements for the proposed P8 events, suggest inserting R4.1.4 that reads: For planning event P8, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability, and islanding. This exceeds the SDT's original intent to require development and implementation of a CAP to avoid Cascading only.	

To remove the performance requirements for instability and islanding for a P8 event, ERCOT suggests the following wording changes to Condition (a): (a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	
Document Name	
Comment	

CHPD appreciates the effort of the SDT to address the directives from FERC Order No. 786, and the recommendations in response to Order No. 754 from the SPCS and the SAMS regarding the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request ("Joint Report")).

Indeed, the primary goal of the Standards Authorization Request (SAR) is to implement the recommendations in the Joint Report. However, the Joint Report states that "***probability of three-phase fault with a protection system failure is low enough that it does not warrant a planning event.***" As such, we believe that the proposed addition of the P8 planning event is overreaching and beyond the scope of the SAR.

The Joint Report does acknowledge *"the existence of a reliability risk associated with the single points of failure in protection system that warrants further action"* and therefore recommended additional emphasis in planning studies to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg. 11). Accordingly, the SAR defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event falls outside the scope of the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan (CAP) if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which includes the P8 event.

With the exception of the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently

enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address FERC's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The creation of the proposed P8 event raises the following issues: The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability and islanding. This exceeds the SDT's original intent to making a 3-phase fault with delayed clearing a planning event thus requiring the development and implementation of a CAP to avoid Cascading only. To remove the performance requirements for instability and islanding for a P8 event, we suggest the following wording changes to Condition (a): 1. For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

2. *Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?*	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
This change appears to require the creation of a model for every outage, without regard for the length of the outage. The requirement is already part of the performance standard through the application of P5 contingencies. The revision as proposed would require a proliferation of cases be developed and maintained and lead to confusion about which case to use. The development of cases for known outages seems appropriate for the operational time horizon but impracticle for the long-term planning time horizon. Reliability of the system during outages in the long-term planning horizon can be studied appropriately through the development of contingencies accompanied with appropriate generation adjustments to be applied to individual known outages within the seasonal period defined by a planning case as opposed to developing a seperate case for each combination of known outages. Further, the changes proposed under 2.1.3 create confusion around which P1 events need must be studied.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled P1 events. P5 are single-phase delayed-clearing contingencies. Modeling such contingencies may help in some, but not all scenarios – it is not a replacement for modeling maintenance outages with a single contingency on an adjacent facility.	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
We need clarification. Oncor does not consider known outages to be a modeling issue. Including known outages with other contingencies appears to be more like a P6, two overlapping singles, than a modeling issue.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled with P1 events.	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light would like further clarity of what is expected.	
Likes 0	
Dislikes 0	
Response	

FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. However; other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and R2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and perform the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

Subpart 2.1.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.1.1 and 2.1.2***, when known outages are scheduled."

Subpart 2.4.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.4.1 and 2.4.2***, when known outages are scheduled."

Likes 0	
Dislikes 0	

Response
Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and R2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. The selection of the know outage immediately follows Requirement R2, Parts 2.1.1 and 2.1.2 alleviating the need to the reference to Requirement R2, Parts 2.1.1 and 2.1.2; or Parts 2.4.1 and 2.4.2.
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment
We believe the proposed change should be simplified as a procedure or technical rationale that identifies what is a known outage should not be embedded within this requirement. The requirement focuses on maintaining system models, not developing procedures or technical rationales. These models must be based on data consistent with NERC Reliability Standard MOD-032-1, Corrective Action Plans, and other data sources. We recommend the SDT follow the acceptable approach suggested within the FERC directive that identifies significant planned outages can be based on registered entity-selected facility ratings or other parameters for inclusion within system models.

Likes 0	
Dislikes 0	

Response	
FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. However; other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and R2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
See comments below.	
Likes 0	
Dislikes 0	
Response	
N/A	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	

TVA supports AZPS's comments. The language is vague and could result in misinterpretation of the requirement. The wording "selected known outages" and "known outages" can cause confusion.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy believes the language in Requirement R1.1.2 could lead to confusion as to which outages are required to be studied. FERC Order 786, paragraph 43 identifies "decreasing the outages to fewer months to include additional significant planned outages" as an acceptable approach. CenterPoint Energy recommends the SDT reconsider this approach and identify a 3-month threshold to capture the outages over which FERC was concerned.	
Likes 0	
Dislikes 0	

Response	
According to the FERC Order No. 786, there is no direct correlation between the time duration of an outage and system impact. A shorter duration outage may be more impactful to the system than a three-month outage. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	No
Document Name	
Comment	
We agree with removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction. The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific. Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard. Therefore, we recommend that 1.1.2. be modified as follows:	

1.1.2 Known Expected outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum: 1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans 1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage) 1.1.2.4 Does not exclude known transmission outage(s) soley based on the outage duration

Likes 0	
Dislikes 0	

Response
FERC Order No. 786 did not limit outages to exclude generation outages. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon. FERC Order No. 786 was explicit in that known outages in the Near-Term Planning Horizon need to be addressed. Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment
We applaud removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction.

The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific.   Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard.

Therefore, we recommend that 1.1.2. be modified as follows:

1.1.2 **Expected** outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum:

1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans

1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage)

1.1.2.4 Does not exclude known **transmission** outage(s) soley based on the outage duration

Likes 0	
Dislikes 0	
Response	
As noted in FERC Order No. 786, known outages in the Near Term Planning Horizon encompass more than just the subset of outages identified in Corrective Action Plans. The SDT provided clarity via Requirement R2, Parts 2.1.3 and R2.4.3 defining parameters that focus the selection of known outages. However, the parameters are not so specific as to limit only those associated with the Corrective Action Plans, as this assumption is not supported by the FERC Order No. 786.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No

Document Name	
Comment	

Texas RE appreciates the Standard Drafting Team's (SDT) continuing efforts to develop a workable definition to implement the Federal Energy Regulatory Commission (FERC) directive in FERC Order No. 786 to include planned maintenance outages of significant facilities in future TPL-001 planning assessments and eliminate the previous six-month bright line inclusion criterion. Texas RE particularly appreciates the SDT's reconsideration of developing a significant outage test based solely upon outages "selected in consultation with the Reliability Coordinator." However, Texas RE remains concerned that the current draft TPL-001-5 R1.1.2 language, if adopted, would be unworkable. Rather than the SDT's proposed approach, Texas RE instead recommends that the SDT require Transmission Planners (TP) and Planning Coordinators (PC) to identify and model known outages selected in accordance with an established procedure that (1) requires selection based on the MW or facility rating criteria identified by FERC in FERC Order No. 786; (2) provides a technical justification for the specific MW and facility rating threshold selected; and (3) does not exclude known outage(s) solely based upon the outage duration.

Texas RE's principal concern with the proposed TPL-001 language, as currently drafted, is that is appears circular. In particular, the proposed TPL-001-5 R1.1.2 first provides that planning models shall represent "[k]nown outages of generation or Transmission Facility(ies) . . . selected for analyses pursuant to Requirement 2, Parts 2.1.3 and 2.4.3 only." That is, the proposed TPL-001-5 R 1.1.2 appears to limit the scope of modeling requirements to a subset of analyses previously identified in TPL-001-5 R 2.1.3 and 2.4.3. TPL-001-5 R 2.1.3 in turn provides that qualifying studies shall include "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2." That is to say, the proposed TPL-001-5 R 1.1.2 appears to reference significant outages identified in the qualifying studies in TPL-001-5 R 2.1.3 while the required qualifying studies in TPL-001-5 R 2.1.3 will be based on those known outages identified in the established procedure set forth in TPL-001-5 R 1.1.2. As a result, the proposed language appears circular. That is, TP or PCs will not know which outages to select for their qualifying studies prior to identifying them using their established procedure. However, that procedure itself depends upon a prior identification of known outages in the qualifying study model run.

A similar issue exists in the proposed TPL-001-5 Foot. This section again requires studies of "P1 events . . . with known outages modeled as in Requirement R1, Part 1.1.2." However, will likely only be able to identify "known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events when concurrent with selected known outage(s)" by performing the analysis in TPL-001-5 R 2.4.3.

In lieu of adopting what appears to be a confusing and circular approach, Texas RE instead recommends that the SDT consider FERC's explicit invitation to define significant known outages based on parameters other than duration. In particular, FERC noted that NERC and the SDT could develop "parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings." (FERC Order No. 786, P. 43). The SDT could implement such a directive by requiring TPs and PCs to select known outages according to an established procedure or technical rationale that, at a minimum, establishes criteria based on MW or facility ratings for significant known outages. Consistent with this approach, the SDT recommends considering revising the proposed TPL-001-5 R 1.1 along the following lines:

1.1 System models shall represent:

1.1.1. Existing Facilities;

1.1.2. Known outages(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1 Establishes a criteria, supported by a technical justification, for identifying significant known outages based on MW or facility ratings; and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

Additionally, it is unclear whose "established procedure" per Part 1.1.4 is to be used, so additional clarification would be helpful.

Likes 0	
Dislikes 0	

Response

The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance

outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
KCP&L incorporates its response to Question 4.	
Likes 0	
Dislikes 0	
Response	
The SDT assumes the pertinent portion of the KCP&L comment to question 4 is to "include language that will allow establishing the scope of contingencies in dynamics to a specific area local to the equipment". To this issue the SDT has provided the capability to tailor the analysis to best fit a particular system. The SDT recognizes the range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The regional differences reflect analysis that is tailored to best examine the system based on unique system characteristics. Accordingly the draft standard accommodates incorporating criteria such as MW, load, topology, and facility ratings to be used as qualifying criteria to identify which know planned outages are candidates for additional assessment as well as providing the flexibility to include other factors (as contained in the entity's procedures). Past studies, local dynamics, as well as other P events (P6, P3) can be used as limiting factors tailored to each entity's system when selecting known maintenance outages to include within the Near Term Planning Assessments and to put bounds on the extent of the assessment.	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	No
Document Name	

Comment	
National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001 and provides the following comment for consideration: Generation or Transmission Facilities outages can be scheduled on a time scale shorter than the Near-Term Transmission Planning Horizon. If a Facility outage previously not studied is selected per guidance provided in R1.1.2 and the selected Facility outage occurs within the Near-Term Transmission Planning Horizon, would that prohibit use of past studies to support the annual Planning Assessment (as otherwise allowed per R2.6)?	
Likes 0	
Dislikes 0	
Response	
Previous planning assessments may be used to inform the planner about the effect of known planned outages that are coupled with P1 events. Additionally, information from analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined and may be used to inform the planner about the effect of a known planned outages in the near term planning horizon.	
Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF and ACES comments.	
Likes 0	
Dislikes 0	
Response	

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so the SDT incorporated your changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
In the last sentence of R1.1.2., SRP recommends changing the word “each” to “all” for the sake of clarity. Also, it is not necessary to specifically list sub-part 1.1.2.2., as there are already other criteria listed which are not solely based on outage duration.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
See comments from MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so the SDT incorporated your changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We have two concerns with the proposed changes: • As currently proposed, the TPL standard only requires P1 events to be simulated when assessing planned outages in the Near-Term Transmission Planning Horizon. However, this is inconsistent with NERC FAC standard FAC-014-2 R6, which require the Reliablity Co-ordinator to consider multiple contingencies when assessing these outages. Therefore, at a minimum, when the Planning Co-ordinator is assessing planned outages occurring in the Near Term Transmission Planning Horizon, they should simulate the contingences that the Reliablity Co-ordinator would simulate when assessing and approving these outages. Hence we propose to replace the requirement to simulate P1 events in R2.1.3 and R2.4.3 with a requirement to simulate the contingencies as specified per R6 of the current FAC-014-2 standard. • The current proposed requirement for selecting outages does not completely address FERC’s order. FERC’s order mentions that planned outages should not result in ‘the loss of non-consequential load or detrimental impacts to system reliability’, whereas the current proposed approach only addresses the loss of non-consequential load.	
Likes 1	Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3;
Dislikes 0	
Response	
FAC-014 is not a planning standard, instead concentrating on system operating limits. FAC-014-02 R6 specifies identifying stability limits for a subset of TPL multiple contingencies. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Based on industry comments the SDT deleted	

Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	

We propose the following changes to Part 1.1.2, "Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .":

- We suggest replacing the term, "scheduled", with the words, "planned to occur", because the term "scheduled" can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word "planned to occur" can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term "scheduled" is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator's scheduled outages.

- We suggest adding, "for applicable system conditions and year (s)", to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

• We suggest replacing "Transmission Planner and Planning Coordinator" with "Transmission Planner or Planning Coordinator" because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles. We propose replacing Part 1.1.2.1 with previous proposed wording of, "Are selected in accordance with documented outage selection procedures or technical rationale". If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations. Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing "schedule outage" to "known outage", and "Transmission Planner and Planning Coordinator" to "Transmission Planner or Planning Coordinator". FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy	

Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	

Comments: Addressing Order 786 without adding a tremendous amount of unnecessary study work is admittedly a difficult problem to solve. FMPA does not support the current draft language because it effectively requires that all outages, regardless of the duration, size or location of the facility (really regardless of any qualifier) must be studied. The reason for this is that non-consequential load shedding is rarely possible to identify without running the power system simulations. Thus in order for an entity to only study outages that cause non-consequential load shedding, that entity usually has to have already studied those outages. The suggested "filter" that the SDT is proposing requires that the Planner already know the result of the simulations. The proposed language introduces a standard requirement that, in practice, will result in entities being forced to "prove the negative" – that is, the focus will become defending how the Planner knew that certain outages would not cause non-consequential load loss.

FMPA asserts that some reasonable qualifiers must exist, and must be used in an attempt to avoid requiring entities to prove the negative. Furthermore, conducting Planning studies on very short duration outages is a waste of time since short duration outages are much more easily (and therefore almost always are) rescheduled in the operations horizon to avoid transmission system reliability risks that are possible. Focusing on longer outage durations increases the likelihood that system performance conditions observed in the studies might actually occur in real time and focuses the study work of the planners more on projects that increase the flexibility of the system (e.g. giving the Operators more tools in their toolbox), rather than on trying to guess at operations horizon conditions or emulate Operations horizon planning work.

Likes 0	
Dislikes 0	
Response	

Past studies as well as P3 and P6 events provide a foundation for establishing a list of what maintenance outages in the near-term need to be addressed. FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. The range of industry

comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy disagrees that the proposed changes meet the directives. The changes go beyond the scope of changes directed in Order No. 786 and will make Planners responsible for evaluating all known scenarios, even outages of limited duration (e.g. 10 minutes?). Also, the standard lacks clarity on whether outages of a Protection System should be considered as well. The lack of specificity regarding outages of limited duration, requires a Planner to study almost every possible scenario Operators may face in the Near Term Planning Horizon. Further, the proposed changes appear to push the standard to a fill in the blank status because it simply requires creation of "an established procedure". The changes to 2.1.3 and 2.4.3 in addition to 1.1.2 appear to create circular logic to require Planners to know the seriousness of the consequences of a scenario they have yet to study.	
Likes 0	
Dislikes 0	
Response	
FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. Additionally FERC order does include known outages of generation, transmission or protection system facilities in the near-term. FERC states that NERC has flexibility in addressing the identified concerns, and outlines several acceptable approaches. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past	

studies as well as P3 and P6 events provide a foundation for establishing a list of what maintenance outages in the near-term need to be addressed. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

We propose the following changes to Part 1.1.2, "Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or Planning Coordinator for analyses . . .":

- We suggest replacing the term, "scheduled", with the words, "planned to occur", because the term "scheduled" can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word "planned to occur" can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term "scheduled" is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator's scheduled outages.

- We suggest adding, "for applicable system conditions and year (s)", to make clear that the selected outages are related to specific timeframes and are not 'hypothetical' outages.

- We suggest replacing "Transmission Planner and Planning Coordinator" with "Transmission Planner or Planning Coordinator" because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, "Are selected in accordance with documented outage selection procedures or technical rationale". If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations. Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing "schedule outage" to "known outage", and "Transmission Planner and Planning Coordinator" to "Transmission Planner or Planning Coordinator". FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

The changes meet the FERC directive but is restrictive on the transmission Planner/Planning Coordinator. In TPL-001-4, only outages 6 months or greater in the Planning Horizon needed to be considered. Requirement R1.1.2.2, as now written, does not permit exclusion solely based on outage duration, which means even one day or one hour outages that are in the near-term Planning horizon cannot be excluded. Perhaps the drafting can consider permitting exclusion of known outages based on some minimum duration (eg. outages less than 1 month maybe excluded, outages between 1 and 6 months may only be excluded if they are not expected to result in non-consequential load loss for P1 events, all outages greater than 6 months shall be included). This makes expectations more clear and avoids the need to develop a technical rationale.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

We propose the following changes to Part 1.1.2, “Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .”:

We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can

- refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing "schedule outage" to "known outage", and "Transmission Planner and Planning Coordinator" to "Transmission Planner or Planning Coordinator". FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing "schedule outage" to "known outage", and "Transmission Planner and Planning Coordinator" to "Transmission Planner or Planning Coordinator". FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	
Comment	
NVE recommends that R1.1.2 be modified to include outages that span the season being studied. For outages in the season being studied that are less than the entire span of the season, the Transmission Planner should be able to select which outage to study based on when in the study season the outage is to occur and the significance of the generation or transmission facilities involved in the outage for the area of the system they are located in.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting	

known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and 2.4.3.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	

OG&E recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and run the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

Subpart 2.1.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.1.1 and 2.1.2**, when known outages are scheduled."

Subpart 2.4.3 (Proposed language)

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.4.1 and 2.4.2**, when known outages are scheduled."

Likes 0	
Dislikes 0	
Response	

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. The selection of the know outage immediately follows Requirement R2, Parts 2.1.1 and 2.1.2 alleviating the need to the reference to Parts 2.1.1 and 2.1.2; or Parts 2.4.1 and 2.4.2.

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	

Comments: Other options could better address concerns in the FERC directive order No 786. The requirement to study outages of any duration in the Near Term Planning Horizon creates burden on the planning process to address the scheduling of outages rather than adequacy of BES infrastructure. Transmission planning is expected to determine performance deficiencies of the system and to mitigate them with planning solutions. Studying impacts of outages with 2 independent unplanned events on top of it would require the creation of additional base cases for (1) each outage in the 1-5 year horizon, or (2) creating cases which encompass all anticipated outages in a season. Next, one would then need to perform all analyses on top of such outages that would be included in the base cases. This essentially creates another layer of contingency analysis which can result in selective N-1-1-1 or more events deep depending on the method used. The results would likely be that impacts could be mitigated by: (a) scheduling appropriately to ensure outages do not overlap, or (b) moving outages into different seasons.

Unintended consequences could result. One example, although unlikely, would be proposing the construction of a transmission project that is built to allow for an outage of a facility for maintenance/rebuild which may be a rare outage occurrence itself. This project just adds a selective 3rd layer of transmission redundancy to the system to allow for reliable system operation during an outage if up to 2 other unplanned events occurred. While this exercise may be of importance to the scheduling of outages and identification of impacts of outages and contingencies, it is best handled by operations planning (operating horizon) which should instead handle the study and scheduling of planned outages beyond the operating horizon and into the Near Term Planning.

Alternative Draft wording for Requirement 1, Part 1.1.2 is provided below.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum: **1.1.2.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); **1.1.2.2.** Considers outage duration(s) but does not exclude known outage(s) solely based upon their duration; **1.1.2.3.** Considers the significance of the generation and Transmission Facility(ies) involved in the known outage(s) for the area of the system in which they are located; and **1.1.2.4.** Considers the expected load levels during the known outage(s).	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons.	

Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis. Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.	
Likes 0	
Dislikes 0	
Response	
FERC Order No. 786 clarified that the TPL Near-Term Planning Assessment is a required and beneficial analysis. A six-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
We suggest replacing the term, "scheduled", with the words, "planned to occur", because the term "scheduled" can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word "planned to occur" can • refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.	

If the term "scheduled" is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator's scheduled outages. • We suggest adding, "for applicable system conditions and year (s)", to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions. • We suggest replacing "Transmission Planner and Planning Coordinator" with "Transmission Planner or Planning Coordinator" because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles. We propose replacing Part 1.1.2.1 with previous proposed wording of, "Are selected in accordance with documented outage selection procedures or technical rationale". If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations. Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing "schedule outage" to "known outage", and "Transmission Planner and Planning Coordinator" to "Transmission Planner or Planning Coordinator". FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range	

of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
The phrase "expected to result" in Part 1.1.2.1 seems to imply that an entity must have studied the known outages to have an expectation of whether or not Non-Consequential Load Loss may occur. LES recommends the following alternate wording to Part 1.1.2.1: "Includes known outage(s) that **in qualified past studies have** resulted in Non-Consequential Load Loss for P1 events in Table 1…"	
Likes 0	
Dislikes 0	
Response	
The SDT has modified Requirement R2, Parts 2.1.3 and 2.1.4 for clarity, indicating that P3 and P6 in addition to past studies can be used as a foundation for establishing the list of known outages for further assessment.	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
R1.1.1.2 requires planners to include known generation and transmission facility outages scheduled within the Near-Term Transmission Planning Horizon and to select the outages studied according to an established procedure or technical rationale. The requirement also states that outages should not be excluded solely based on outage duration. FERC Order 786 states that acceptable approaches for	

addressing the outage concern include decreasing the threshold to fewer months or including parameters for identifying “significant planned outages” (page 33). Planners should review planned outages for the season under study and use technical rationale to determine whether an outage should be included or excluded from the study. Per FERC Order 786, planners should have the flexibility to exclude outages based on their technical rationale. Outages not deemed significant for the TPL assessment will be included in operations studies as the outage approaches. CHPD has three concerns related to this proposed language regarding known outages in R1.1.2.: 1. The nature of the outage, i.e. scope of work, has an effect on the system but the transmission planners do not necessarily know how a facility will be removed from service. For example, for maintenance of a relay system, there are many options for performing the maintenance with impacts ranging from delayed clearing to no system impact at all: 1) simply take the maintenance outage with all other systems energized (relying on delayed clearing); 2) take the local terminal out of service (likely eliminating the delayed clearing risk); or 3) bypass the normal breaker and relays and feed the line from a bus tie or transfer breaker. CHPD requests the standard provide coordinators with flexibility to assume the scope and nature of outages. 2. For overlapping, un-coordinated outages, the Planning Authority or Transmission Planner should be given authority to, when appropriate, move the outages for the purposes of the planning study so they do not overlap. This activity is frequently performed for outages in the Operations Timeframe, but no construct exists to do this for outages in the Planning Horizon. The proposed Standard should provide such a construct. 3. For situations in which new infrastructure for a Corrective Action Plan cannot be built prior to an outage, e.g., an outage scheduled in 1.5 years requires a capital project that will take 3 years to build, the proposed Standard should allow for the interruption of firm transmission service. FERC’s concern was that properly planned outages should not lead to load shedding. FERC Order 786, paragraph 41. Allowing for interruption of firm transmission will allow critical outages to be taken while avoiding non-consequential load loss.

Likes 0	
Dislikes 0	

Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
These are planning studies, not operating studies. Outage coordination studies are currently done by the operations department as part of operations seasonal planning. Adding outage coordination studies to the Near Term Planning Horizon [1-5 years] will increase the planning work load without any real reliability improvement. The reason being that planned outages are currently part of transmission planning in both the Near and Long Term Horizons. It is a matter of understanding the steady-state contingency results. When looking at future system behavior, N-2 steady-state contingency analysis will reveal system performance with a single BES element out of service followed by a P1 event. Two element are out of service N-2. This is only a starting point. When N-2 contingency analysis does not show any performance violations, the system should be able to remove BES elements from service without issue. If a performance violation is found, then further analysis is required (N-1-1). We do not need a new requirement. If the requirement is added, the stability portion should be removed. Including stability analysis to the requirement will make it overly burdensome and will not improve reliability. Stability analysis software is not well suited for automation and the TPs and PCs can not reasonably be expected to perform stability analysis for every valid P1 contingency for each possible BES outage. The language of the requirement calls for contingencies which are "expected to produce more serverer system impacts". The only way to know the expected stability impact is to study it. Therefore, the requirement actually requires all planned outages to be studied using stability analysis and then to use those results to support the selection of a contingency subset to be studied. This is a circular argument. Stability analysis of planned is not needed for reliability.	
Likes 0	

Dislikes 0	
Response	
FERC Order No. 786 clarified that the TPL Near-Term Planning Assessment is a required and beneficial analysis. Specifying particular outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. FERC Order No. 786 did not limit outages to exclude dynamic assessments. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State partially agrees but has some reservations regarding the specific language and overlaps with existing P3 and P6 contingency categories. Requirement 1.1.2.2 runs counter to Requirement 1.1.2 which allows outage selection based on technical rationale. Technical rationale would include time-dependence. The inclusion of major outages regardless of time duration effectively adds an outage coordination aspect to performing the TPL assessment. Outage coordination is already performed by Transmission Operations. Requirement 1.1.2 effectively describes a category P3 or P6 contingency.	
Likes 0	
Dislikes 0	
Response	

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Part 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS respectfully asserts that the proposed criteria under Requirement R1, Part 1.1.2 presents an overly complicated response to the Commission's directive in Order 786, Paragraph 43. Specifically, the Commission's directive allowed for the response to the directive to be a simple reduction of the 6 month time period. Such reduction would provide objective criteria for the entire industry to utilize to determine whether or not planned outages should be included in their planning assessment. AZPS is concerned that the proposed criteria under Part 1.1.2 is subjective in nature and could result in the potential for inconsistency relative to the inclusion of outages in planning assessments, e.g., outages of three (3) months or less could be implicated by some entities despite such outages creating unnecessary study burden with little to no reliability benefit wherein other entities could exclude such short-term outages. To ensure that the criteria provides more objectivity relative to the inclusion of outages in planning assessments, which would increase the overall consistency and value of planning assessments generally, AZPS recommends that the SDT reconsider the currently proposed criteria and replace it with criteria that requires outages to be included where such outages meet a definitive time period of "more than 3 months." AZPS respectfully asserts that short term outages should be studied and prepared for in the Operating horizon and not in a planning assessment and, further, that the potential for inconsistency between planning assessments would reduce the proposed reliability benefit anticipated by the currently proposed criteria. For these reasons, AZPS recommends replacement of the currently proposed criteria with a simplified criteria requiring inclusion of outages that are anticipated to last more than three months.	
Likes 0	
Dislikes 0	
Response	

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA appreciates that the reference to consultation with the Reliability Coordinator has been removed and that "Transmission" was added to Near-Term Transmission Planning Horizon. For R1.1.2.2 BPA does not believe it would be reasonable to require justification for every known outage that is not included. The way R1.1.2 is written, it seems to imply that an outage excluded based on duration should also not meet the established procedure or technical rationale.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
John Seelke - LS Power Transmission, LLC - 1	

Answer	No
Document Name	

Comment

The language in Part 1.1.2 is fine; however the language added to R2 Parts 2.1.3 and 2.4.3 that is referenced in Part 1.1.2 is confusing. Page 8 of the posted Technical Rationale document contains the rationale for changes to R2 Parts 2.1.3 and 2.4.3:

"Consistent with FERC's directive, the drafting team modified Requirements **R2 Parts** 2.1.3 and 2.4.3 to further recognize the intent to limit required study to only those known outages that are expected to produce severe System impacts on the PC/TP's respective portion of the BES."

LSPT agrees with this rationale. However, the changes to Parts 2.1.3 and 2.4.3 do not accomplish this objective. Since both 2.1.3 and 2.4.3 have the same added language, the concern is illustrated in 2.1.3 only, which states the following regarding the analysis required by the Planning Coordinator or Transmission Planner, with the added language bolded:

2.1.3. P1 events in Table 1 **expected to produce more severe System impacts on its portion of the BES**, 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.

The proposed change allow the PC/TP to **not** evaluate all P1 events; the PC/TP must only evaluate those P1 events in Table 1 "expected to produce the most severe System impacts on it portion of the BES." In other words, the P1 events in combination with "known outages" that produce the most severe System impacts may be a different set of P1 events..

LSPT's proposed changes to 2.1.3 (and correspondingly to 2.4.3) will correct this unintended consequence:

2.1.3. P1 events in Table 1, with known outages **that are expected to produce more severe System impacts on its portion of the BES** modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

Likes 0	
Dislikes 0	

Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	
We understand the need to address FERC Order No 786; however, the additions to 1.1.2 are creating additional unnecessary modeling work that we do not believe provides additional value to reliability.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	No
Document Name	
Comment	

OUC believes the proposed Requirement 1.1.2. leaves too large of ambiguity in what needs to be tested. The intent of what is required to be tested is not clear, and appears on the surface to overlap significantly with the Operations Planning realm. The current standards provide enough parameters to include outages into the base case (using the 6 month outage duration as a threshold). The proposed changes reads as if it's requiring long-term transmission planners to study operational planning studies under the "Near-Term Transmission Planning Horizon". OUC does not believe the TPL requirements should include operational planning studies that should otherwise be included under the TOP standards (i.e. TOP-002-4). By not defining an outage duration, the requirement now appears to welcome any and all outage scenario testing, which should otherwise be completed under the TOP standards. Although Requirement 1.1.2.1 was added to limit the outages selected, for most it would be unclear what scenarios would result in non-consequential load loss, thus not providing enough of a parameter to limit the outages needed to be tested. Suggestion: OUC would suggest keeping the outage length as a parameter in order to filter the outages that should be studied in the Near-Term Planning Horizon. In understanding the 6 month outage duration not being inclusive of what the drafting team may be looking for, perhaps limiting the outage duration to 3 months would include enough of the key outages that should be studied, while not including all outages which would otherwise need to be analyzed under Operations Planning scenarios.	
Likes 0	
Dislikes 0	
Response	
Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
N/A	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

As proposed, we believe that R1.1.2.1 involves the creation of hypothetical outages to evaluate and include in the transmission assessment.

From the Order 786, paragraph 42, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." Most transmission maintenance outages are scheduled in the operating horizon, after considerable review and analysis of expected system conditions in the operating horizon. These outages may be daily, weekly, or of longer duration, but still they are planned and scheduled in the operating horizon and not the planning horizon. Therefore, from a planning perspective, few if any transmission outages will be included in the base case peak or off-peak models for analysis and development of the Planning Assessment because these maintenance outages have not been scheduled in the planning horizon.

The Commission goes on to state in paragraph 44 that "these potential planned outages must be addressed, so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon". In other words, the Commission wants us to speculate on the start and stop times of the maintenance outages, effectively creating hypothetical outages to consider for analyses. From our perspective the language of this paragraph of Order 786 is ambiguous. The Commission also stated in paragraph 44 that category P3 and P6 contingencies do not cover generation and transmission maintenance outages, but during the webinar, it was suggested by a member of the standard drafting team that the allowance of system adjustments following the planning maintenance outage event was the reason for FERC's disapproval. Is it the drafting team position that if the analyses were performed without system adjustments between the outage events, then FERC would not object? We did not read that response in Order 786 and request that the Standard Drafting Team provide reference that analyses of P3 and P6 events without system adjustment, other than make-up power, would provide an acceptable method for determining system adequacy during maintenance, planned or hypothetical, outages. However, we question why generation redispatch or other operating guides cannot be developed, if needed, to facilitate the performance of maintenance outages in the planning or operating horizons.	
Likes 0	
Dislikes 0	
Response	
FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. FERC Order No. 786 did not limit outages to exclude generation outages. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon. FERC Order No. 786 was explicit in that known outages in the Near-Term Planning Horizon need to be addressed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments, and to lessen the ambiguity of the FERC Order. The SDT has incorporated language in Requirement R2, Parts 2.1.3 and 2.4.3 that provides flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.	

The SDT should not and cannot provide clarity behind the reasoning of FERC. The webinar question referenced in your comment was regarding using basecase adjustments prior to replicating P1 events, which is permitted. In the Webinar, one example of what is different between performance requirements of a P1 vs. P6 was given as “system adjustments are allowed”, another example of a difference between performance requirements is load drop is allowed for a P6 and not allowed for a P1. It should not be assumed that one example given in the webinar between performance requirements of a P1 vs. P6 is the only reason why a P6 is insufficient.

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

Requirement 1, Part 1.1.2.1., does not provide a clear demonstrable criterion for outage selection. In order to conclusively determine “expected” Non-Consequential Load Loss during an N-2 event, studies must be performed to determine the response of the system. Therefore, this requirement, as written, implies that the Transmission Planner must consider *all* known outages. In Order 786, paragraph 43, FERC suggested that a selection parameter of facility ratings could be used. Use of a facility rating threshold in the standard would provide needed clarity to Transmission Planners and result in greater consistency.

Likes 0	
Dislikes 0	

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
N/A	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
N/A	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

N/A	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO agrees with the changes in Part 1.1.2 with the exceptions noted in the response to Question 4 below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
There is no one size fits all country wide method of identifying which known outages are best included in this section. The SDT has put in place a mechanism that allows reasonable local tailoring to the list of known outages by the TP or PC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments.	
Robert Ganley - Long Island Power Authority - 1	

Answer	Yes
Document Name	
Comment	
Section 2.7, related to Corrective Action Plans – there appears to be an incorrect reference to Section 2.4.3. This reference should be changed to the new section 2.4.4	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment; the SDT has since corrected this error.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Landis - Platte River Power Authority - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	Yes
Document Name	
Comment	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. ***Do you agree with the proposed implementation plan?***	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	

The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.

However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the

number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.) **Suggestion**: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Jeff Landis - Platte River Power Authority - 3	
Answer	No
Document Name	
Comment	
PRPA supports JEA comments. The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5. However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an	

extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities. We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different Unofficial Comment Form Project 2015-10 and Single Points of Failure | February 2018 4 challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.) Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

Should be 2 years longer.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No

Document Name	
Comment	
We are not in agreement with the changes, therefore the implementation dicussion is a mute point at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	

Comment	
Duke Energy does not agree with the proposed Implementation Plan. Depending on system conditions, it is anticipated that when using Dynamic Load Modeling, that an entity could see a great number of its Facilities fail the performance requirements. Failure of the performance requirements could result in significant upgrades, which take time to implement. With the potential for significant upgrades to a majority of applicable Facilities, Duke Energy cannot agree with the Implementation Plan proposed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
See Exelon TO Utilities Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	
Comment	
FMPA supports the comments of JEA on the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time	

than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
Louisville Gas and Electric Company and Kentucky Utilities Company (LKE) supports providing Planning Coordinators (PCs) and Transmission Planners (TPs) 36 months until the effective date of the Standard to develop a procedure or technical rationale for selecting known outages of generation and Transmission Facilities, a process for establish coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis, and additional base case models and analysis. However, LKE believes that requiring “the planned System [to] continue to meet the performance requirements in Table 1 until 96 months after the effective date of Reliability Standard TPL-001-5” is too long. The three years before the effective date plus 8 years is 11 years. Other NERC standards do not have an 11 year time frame to fix an identified reliability risk to the BES.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
See comments from MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Since we have concerns with the ambiguity of the proposed P8 event (see our comments to question #1), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No

Document Name	
Comment	

KCP&L recommends extending to 60-months the preparation period prior to the effective date of the Standard.

In the alternative, provide flexibility or a process to extend the 36-month period based on the TP and PC's evaluation to implement the revised TPL-001-5 Standard.

Concern

The proposed Implementation Plan's time periods do not fully consider the differences in system sizes, complexity, and design elements.

Additionally, with the Standard's assessment scope expansion, the periods offered in the Plan need to consider barriers entities face staffing or contracting for the qualified personal to complete studies and implement CAPs.

KCP&L identified activities it anticipates will be required under the Standard that make the Plan's time periods insufficient to complete implementation of the proposed Standard. Here is an example:

- Changing and updating contingency lists will extend beyond the 36-month period because of the complexity and size of the undertaking and required vetting.

Beyond a single implementation activity, the implementation of the revised Standard will require long-duration, contingent, inter-related activities that, taken individually may fall within the 36-month period but, to collectively complete all the activities, will extend beyond the 36-month period. For example:

1. The best-case scenario to update and test dynamics software will take at least 12-months. The estimated period is without consideration of challenges to:

- Schedule the software upgrade and testing;
- Incorporate the additional P8 events and the re-alignment of Extreme events into the software; and

- Address the many "small" changes that will affect the planning models and assessments.

The proposed revision's specific and required assessments are contingent on updating and testing dynamics software. The period to complete the upgrade and assessments we easily see extending beyond the 36-month proposed implementation period.

A 36-month period to complete required assessments seems arbitrary when placed against the wide spectrum of applicable systems. In consideration of system differences, we recommend the 60-month period or, in the alternative, a process to extend the period based on TP and PC's evaluation to implement the revised TPL-001-5 Standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE appreciates the SDT's efforts in putting together the proposed Implementation Plan. Texas RE notes that, in its experience, registered entities have had significant issues understanding and following implementation plans. Texas RE therefore strongly encourages the SDT to carefully review the proposed Implementation Plan to ensure that is not ambiguous, vague, or confusing to understand.

To that end, Texas RE notes two aspects of the proposed implementation plan that could lead to potentially significant industry confusion. First, Texas RE notes that in establishing the requirement to complete planning assessments 36 months following the effective date of the standard approval, the proposed Implementation Plan is silent regarding the specific Standard Requirements that are actually implicated. Texas RE recommends that the SDT not merely rely on references to "planning assessments," but actually insert specific references to the Requirements subject to the 36-month planning assessment compliance threshold to reduce any possible ambiguity. Second, the proposed implementation plan provides that the requirement to implement Corrective Action Plans (CAPs) to be "the first calendar quarter 84 months following applicable regulatory approval of TPL-001-4." The effective date of the FERC Order approving TPL-001-4 is December 22, 2013. As such, the CAP requirement would, on its face, be due on March 1, 2020. Because TPL-001-5 will not become effective for at least 36 months following any applicable regulatory approvals, this requirement would trigger *prior* to the effective date of the proposed TPL-001-5 Standard. This appears to be in error, and Texas RE suggests that the SDT revise this aspect of the implementation plan accordingly – perhaps by inserting a reference to TPL-001-5 instead of TPL-001-4.

In addition to these issues, Texas RE presently understands the implementation plan, as currently drafted, to provide the following glide path to full implementation of the proposed TPL-001-5 Standard:

First calendar quarter 36 months following regulatory approval.

· The effective date of the standard is the first day of the first calendar quarter 36 months following the effective date of the applicable governmental authorities order approving the standard. This date serves as a starting point for the implementation plan.

· In accordance with the Initial Performance section, applicable entities must complete the planning assessment without CAPs by the effective date of the standard, or 36 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes there is no requirement mentioned. In the interest of clarity and not being vague Texas RE strongly recommends the implementation plan specify which requirement this date refers to.

60 months following regulatory approval.

· In accordance with the Initial Performance section, applicable entities must develop any required CAPs 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 b, c, and d, and P8 by 24 months following the effective date of the standard, or 36 months plus 24 months, or 60 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes this is also indicated in the Compliance Date section.

For 84 months following regulatory approval

o Texas RE noted the issue with the standard version above in reference to the Note Regarding CAPs. Assuming this should indeed specify TPL-001-5, rather than TPL-001-4, CAPs applying to the specified categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Form Transmission Service.

132 months following regulatory approval

o In accordance with the Compliance Date section, entities have 96 months from the effective date to end the use of CAPs developed to address failures to meet Table 1 performance requirements for P5 and P8 events only. The way this is written indicates entities have 36 months following the effective date of the applicable governmental authorities order approving the standard *plus 96 additional months* to end the use of CAPs. Is it the SDT's intent that this be *132 months from the effective date of the applicable governmental authority's order*? This timeline seems excessively long and would unnecessarily burden registered entities to prove it is doing anything to support the reliable operation of the grid based on an assessment.

In addition to the two confusing aspects noted previously, Texas RE noticed additional areas in which this implementation plan lacks clarity.

· First, the implementation plan uses different but similar terms: Effective Date, Compliance Date, and Initial Performance Date. While implementation plans in the past have used Effective Dates to indicate the starting point at which all activities are based upon, the use of the Effective Date is inconsistent in this plan. The implementation plan calculates when applicable entities must do planning assessments from the effective date (must be by the effective date for planning assessments without CAPs) as well as it calculates when any required CAPs 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 b, c, and d, and P8 must be developed (24 months following the effective date). It is *not* used to calculate the date by which applicable entities must end their use of CAPs, nor is it used to calculate the date by which CAPs should not include Non-Consequential Load Loss and/or curtailment of Firm Transmission Service (see Note Regarding CAPs). This date is calculated based upon the effective date of the applicable governmental authority's order. To improve clarity, the effective date should be used consistently.

· Texas RE inquires as to the difference between the terms Compliance Date and Initial Performance Date. The Compliance Date section contains the same information as the second paragraph of the Initial Performance section. Are they intended to mean two different things since two different terms are used?

· It is also unclear to which requirements the actions refer. Are we to assume that if the requirement is not mentioned specifically, it is enforceable on the effective date of the standard?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline. In addition, by the time the TPL-001-5 becomes effective which is 36 months after the approval date TPL-001-4 would have met the 84-month period so there is no overlapping or confusion.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	No
Document Name	
Comment	
The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5. However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, We do not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.	

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.) Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, We recommend NERC survey the industry (PCs, TPs and Facility owners) with another ***Request for Data Under Section 1600 of the NERC Rules of Procedure*** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ***ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)***.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	

TVA supports JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
See comments below.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

SCE expects that bullet D in the revised footnote 13 as currently written will bring over half of the existing SCE protection systems into scope for assessment of delayed clearing for P5 events. Without a completed assessment of the impact to reliability, SCE expects that some substations will require Corrective Action Plans to bring protection systems to full redundancy or system reliability within performance requirements. SCE proposes that the implementation plan keep the initial 36 months until Assessments must include the new models and studies but increase the time for developing Corrective Action Plans for P5 and P8 contingencies to an additional 60 months instead of 24. Similar to when TPL-001-4 first became effective, certain categories of contingencies were recognized as needing additional time for Transmission Planning entities to raise the bar on system performance. SCE proposes that the same latitude be applied to TPL-001-5's proposed higher standard of system performance.	
Likes 0	
Dislikes 0	
Response	
TPL-001-5 footnote 13d was revised to include monitoring of trip coils. Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of P8 categories, the SDT believes that 24-month for developing Corrective Action Plan is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light supports JEA comments.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
The implementation plan requires Oncor to perform contingency analysis for P8 contingencies and develop a Corrective Action Plan for any issues resulting from a P8 contingency. Oncor does not agree with the requirements pertaining to P8 contingencies as outlined in the first comment above. If the P8 contingency is adopted, the implementation time needs to be longer due to the effort required to gather the required information and perform the first analysis.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
The timeframes outlined in the implementation plan appear to be adequate to respond to the new requirements.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	

Comment	
The implementation plan seems reasonable from a planning perspective. Depending on the number of system protection upgrades needed, the completion of these upgrades by the desired date may be a challenge.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	Yes
Document Name	
Comment	
While we do not agree with the additional requirements, we believe 24 months is reasonable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
References to P8 would need to be removed from the implementation plan if the proposed changes are made to move the P8 events back to Extreme Events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	

Answer	Yes
Document Name	
Comment	
The implementation plan is ok other the plan associated with P8. Manitoba Hydro doesn't agree that P8 should be added.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The Implementation Plan allows sufficient time to coordinate CAPs with external entities and meet compliance	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes

Document Name	
Comment	
We agree with the implementation timeline, but the proposed revisions still need some work.We agree with the implementation timeline, but the proposed revisions still need some work.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	
Document Name	
Comment	
LES supports the comments provided by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	
On page 2 of the implementation plan, there is a statement in the third paragraph which may require some clarification. In "…failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed" does the phrase "may not be mitigated" imply that interim Operating Procedures will not be allowed, or is this an acknowledgement (and acceptance) that there may be instances in which an interim Operating Procedure may not be sufficient to meet the System performance requirements? We assume the second interpretation is what was intended, but it is recommended that this statement be clarified to eliminate the possibility of misinterpretation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

The 60 month implementation plan is appropriate as a significant amount of protection and control related data and design drawings will have to be acquired and reviewed in order to facilitate the ability to study the required additional dynamic simulations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

4. *Do you agree with the proposed revisions to TPL-001-4?*	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

ERCOT would recommend two further revisions.

First, ERCOT recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete ", at a minimum:" from section 1.1.2 and replace with the full text of proposed 1.1.2.2 ("does not exclude known outage(s) solely based upon the outage duration.").

2. Delete sections 1.1.2.1 and 1.1.2.2.

Second, ERCOT recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are "expected to produce more severe System impacts on [the responsible entity's] portion of the BES." However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete proposed additional language “expected to produce more severe System impacts on its portion of the BES,” from section 2.1.3. 2. Delete proposed additional language “expected to produce more severe System impacts on its portion of the BES,” from section 2.4.3.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with some comments and revisions have been made to the draft standard.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
See comments in response to question 2.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled P1 events. P5 are single-phase delayed-clearing contingencies. Modeling such contingencies may help in some, but not all scenarios – it is not a replacement for modeling maintenance outages with a single contingency on an adjacent facility.	

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	

Oncor believes that the definition of ‘non-redundant components of protection system’ per Table 1, item 13 is consistent with FERC order 754 (2012) as well as NERC’s technical paper on ‘Redundancy of Protection System Elements’ (2008) – However, this definition coupled with category P5 and newly added category P8 expands much beyond FERC Order 754 for the following reason:

- FERC Order 754 data request limited the buses to be analyzed by the voltage level and number of circuits associated with the bus. These criteria clearly were targeted to pick the more critical stations from reliability and stability stand point.
- The enforceable definition of the non-redundant protection scheme without general guidelines on where to apply such definition, in essence expands the assessment to the entire system without consideration to the criticality of the elements. Generally speaking, it is more common to have non-redundant schemes at smaller stations (lower kV, fewer transmission circuits, remote locations, etc.), as they have minimum system impacts during faults, and tend to have only localized issues (or outages that are not an issue).

Oncor recommends the assessments per category P5 and P8 should be limited to defined critical stations similar to FERC 0rder 754.

The redundancy as per Table 1-13(a) through Table 1-13(c) are reasonable replacement of ‘relay failure’ as per TPL-001-4. However, Oncor is not in agreement with Table 1-13(d) for the following reason:

In Oncor’s experience, failure of DC control circuitry is an unlikely event in general. Additionally, if the circuits were to fail, the result would be a breaker failure (stuck breaker) resulting in operations of breaker failure schemes – avoiding remote delayed clearing which is much longer than breaker failure delay. Oncor believes this requirement is not sufficient justification to require assessing DC control circuitry.

Likes 0	
Dislikes 0	

Response
The P8 planning event was removed and made an extreme event. The language in the standard allows the TP/PC to develop a technical rationale in order to determine the Contingencies expected to produce more severe impacts on its portion of the BES. This technical rationale can include critical stations. However, the contingency selection must include generators, transmission circuits, transformers, shunt devices and buses. Understanding the Order 754 only evaluated specific buses and had a brightline criteria. The SAMS and SPCS report was clear to expand the requirements to study more than the facilities included in the SAMS and SPCS report. The SAMS and SPCS recommendations did not recommend a change to this list of faulted elements and the SDT feels that removing generators, transmission circuits, and transformers is not in the best interest of the reliability of the BES. There are many instances where a disturbance followed by a breaker failure results in the exact same study as a disturbance followed by a protection failure. There could be slight differences in clearing times and the TP/PC can choose to run P4 and P5 as one study using the longest clearing time. However, in the event of a bus fault followed by a bus differential protection failure, there is a single relay communicating to several breakers which are the breakers attached to the bus. A bus fault on a breaker and a half scheme or double breaker double bus scheme are particularly problematic. In the P5 event for this type of protection failure, none of the breakers which should open to clear the fault will get the signal from the relay in order and clear the bus fault. This makes the bus differential P5 event significantly more severe than the P4 event. The FERC Order 754 Section 1600 data request was specific to bus faults followed by a single point of failure of the protection system. In cases where a P4 analysis at a specific location will be the same as a P5 analysis. Example: failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open in order to clear the fault. Therefore, the P4 and the P5 is the same simulation.

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	

Comment	
We agree with some of the revisions, but believe the establishment of a P8 event is not appropriate, the proposed criteria for including planned outages reaches too far into the Operating Horizon, and that Footnote 13 should be made clearer to avoid varying interpretations.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees and P8 was removed. A three-phase fault followed by a protection failure remains an extreme event. The SDT added clarifying language for footnote 13 to the technical rationale which follows the standard. In IRO-017, there are outages studied in the Time Horizon: Operations Planning, but IRO-017 R4 states that the Planning Assessment for outages must be coordinated with the RC and the Time Horizon: Long-Term Planning. So there is not an overlap since the Time Horizons are different. Also, without a change to TPL-001 for studying outages, there is a gap for IRO-017 R4 requirements.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
City Light supports JEA comments.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments provided by JEA and City Light. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2). This revision will address the Commission's directive from Order No. 754 and is consistent with the recommendations from the Joint Report regarding the three phase faults.	
Likes 0	
Dislikes 0	
Response	
The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe Requirement 2, Part 2.1.3 and Part 2.4.3 should complement our previous recommendation for Requirement 1, Part 1.1.2 on basing significant planned outages according to registered entity-selected facility ratings. The required studies should allow registered entities flexibility on which planned outages are necessary for P1 event studies, particularly those outages that incorporate Facility expansion, construction, or rebuilds and other solutions documented in Corrective Actions Plans.	

2. The reference to open circuit within Footnote 13c needs further clarification. The term "dc supply" is ambiguous and needs to confirm the accepted configuration for substation control houses. Will this require two batteries, two separate battery chargers for a single battery bank, or onsite backup generation as the accepted configuration? The technology currently available for detecting open circuits is problematic and can introduce addition points of failure when in service. We recommend clarifying the reference to read "A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for abnormal DC voltages."	
Likes 0	
Dislikes 0	
Response	
1. Changes were made to the language related to outages along with revisions to parts 2.1.3 and 2.4.3. The TP/PC needs to have a technical rationale that identifies which outages are "significant". 2. The station DC supply includes station battery, battery chargers and non-battery-based dc supply. This list is included in the NERC Glossary of terms under "*Protection System*". There is a NERC Technical Paper dated November 2008 titled *"Protection System Reliability Redundancy of Protection System Elements*" which explains why monitoring an "open circuit" is required. The SAMS and SPCS recommendation from Order 754 and Section 1600 data request aligns with most of the elements in the NERC Technical Paper. For reference Figure 5-12 is copied from this technical paper.	

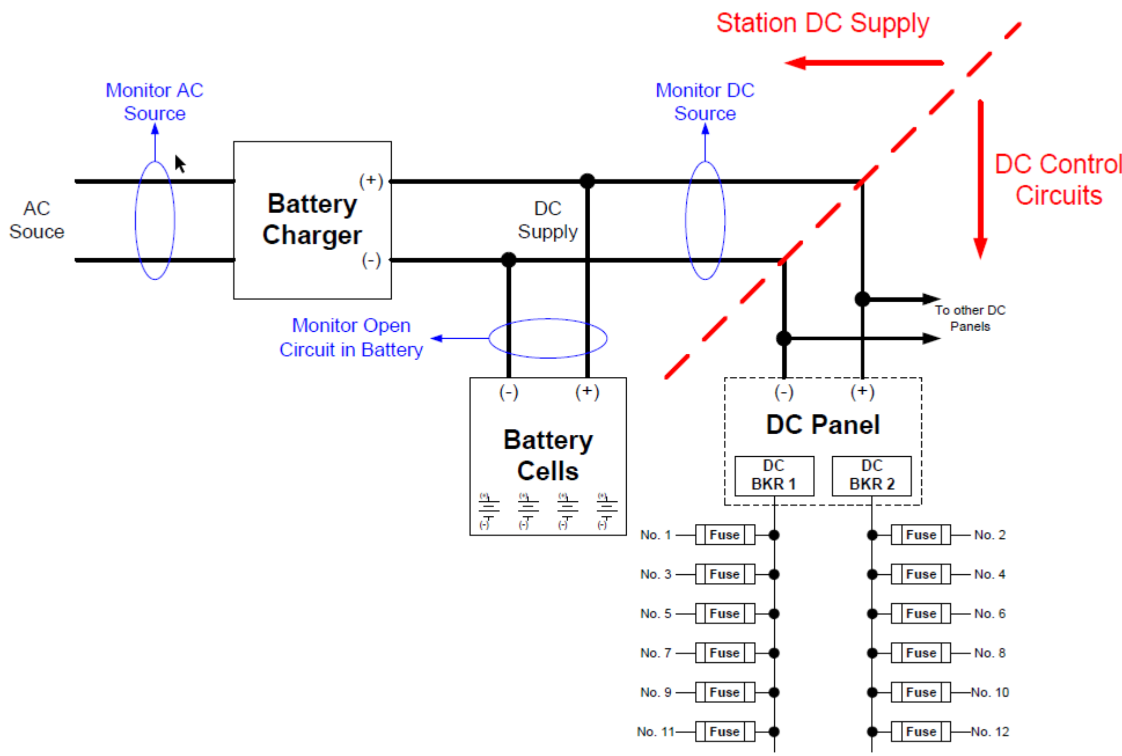

Figure 5–12 — Station DC Supply and Monitoring

For these reasons monitoring of both open circuit and low voltage are required **OR** redundant meaning two batteries, and redundant meaning two battery chargers, etc. The SDT is sympathetic to the fact that open circuit may be problematic and could introduce additional points of failure. However, the FERC directive, SAMS and SPCS Order 754 recommendations and NERC Technical Paper needs to be followed.

Richard Vine - California ISO - 2	
Answer	No
Document Name	

Comment	
The California ISO generally agrees with the proposed revisions to TPL-001-4, but would recommend two revisions. First, the California ISO recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786. The California ISO recommends the following specific revisions based on the foregoing concerns: 1. Delete ", at a minimum:" from section 1.1.2 and replace with the full text of proposed 1.1.2.2 ("does not exclude known outage(s) solely based upon the outage duration."). 2. Delete sections 1.1.2.1 and 1.1.2.2. Second, the California ISO recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are "expected to produce more severe System impacts on [the responsible entity's] portion of the BES." However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted. The California ISO recommends the following specific revisions based on the foregoing concerns: 1. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.1.3. 2. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.4.3.	
Likes 0	
Dislikes 0	

Response	
The SDT removed the circular issue be removing the requirement to model "known outages" in R1 and added language to study known outages in Requirement R2, Parts 2.1.3 and 2.4.3. Other revisions to these sections should satisfy California ISO. The SDT hopes the added language to Parts 2.1.3 and 2.4.3 addresses the California ISO concern on the language "expected to produce more severe System impacts on its portion of the BES".	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SCE's key disagreement with the proposed revisions is the language of bullet D of Footnote 13. SCE provided comments on bullet D during draft 1 regarding a monitoring provision like that contained in bullets B & C. The drafting team provided feedback as to its decision at that time due to limitations of PRC-005 monitoring. For draft 2, SCE responded to the direct feedback with additional substantive information for consideration regarding the role PRC-005 monitoring that allows extended maintenance intervals because the equipment will indicate if there is an issue. However, the drafting team didn't provide a rationale for the continued rejection of SCE's proposal to exclude control circuitry through the trip coils that are monitored and reported. Respectfully, SCE wishes to reiterate the reliability value in monitoring control circuitry combined with higher periodicity testing requirements for components such as electromechanical lockout relays required by PRC-005.	
Likes 0	
Dislikes 0	
Response	
TPL-001-5 footnote 13d was revised to include monitoring of trip coils.	

The SDT understands that monitoring PRC-005 results in extended maintenance periods of some protection systems. The purpose of TPL-001-5 is to give directions to the TP/PC of the elements that must be studied. The SDT does not see a direct correlation between PRC-005 and TPL-001 since a planning standard and a maintenance standard are very different.

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	

- The NERC Drafting Team should consider limiting single points of failure at Generation Facilities and develop a criteria for applicability to GOs (Example: Limit GO applicability to relays associated to interconnection points and not all relays that are part of PRC-005). It is understood that this Standard does not directly apply to the GO under the Applicability section of this Standard but it appears they could ultimately be required to create Corrective Action Plans (CAPs) by the Transmission Planner or Planning Coordinator for non-redundant components of a Protection System. Also, singular generation units are already accounted for in Planning Assessments so single points of failure at these locations should be exempt from this analysis. Additionally, the SDT should consider only requiring GOs to identify single points of failure to be included in Planning Assessments but not require GOs to develop Corrective Action Plans (CAPs). The proposed revisions as written, when applied to GOs, would provide little reliability benefit but could potentially result in significant cost associated with upgrading Facilities.

- Single protective relays and single control circuitry referenced in footnote 13 are prevalent for equipment at voltages 100kV -229kV and generally do not meet the redundancy requirements in the proposed revisions of this Standard. The SDT should consider making footnote 13 applicable to equipment at 230kV and above.

- Single communication systems referenced in footnote 13 should be clarified by the SDT and state backup communication can use time delay functionality (does not use communication system) if relays can clear normally. The current wording implies that two independent communication paths are required to report issue back to the Control Center. Additionally, the SDT should

consider allowing weekly communication checkbacks that report back to the Control Center as a method to meet the communication requirements in footnote 13. • A single dc supply referenced in footnote 13 would add significant cost with little benefit for dc supply open circuit monitoring in real-time. The SDT should consider addressing dc supply open circuit during quarterly battery maintenance in PRC-005-6 to reduce cost impact to industry. The estimated total cost for installing dc supply open circuit monitoring would be roughly $50,000 per location.	
Likes 0	
Dislikes 0	
Response	
The SAMS and SPCS report as a result of Order 754 identified a risk to the BES for both GO and TO facilities and did not recommend a change to the list of faulted elements. Therefore, limiting the single point of failure to generation facilities is not in the best interest of the reliability of the BES. The SDT discussed at length adding either GO and/or TO as applicable entities to ensure that CAP are actually implemented. It was determined that the SAR for this SDT does not allow this change. Limiting TPL-001-5 to EHV only will not eliminate the risk to the BES identified in the SAMS and SPCS Order No. 754. The SDT cannot add a timeframe for reporting communication failures to the control center since this adds a requirement to the TO or GO. The SDT does not believe they have the authority to add TO or GO as an applicable entity. The SDT understands that implementing either monitoring or adding redundancy to DC supplies can be problematic. However, the first step is to determine in the Planning Assessment if there is a risk to the BES as a result of a single line to ground fault followed by loss of the DC supply. If there is a risk to the BES, it does not seem like this added cost to implement redundancy is high compared to the risk.	
Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane	
Answer	No

Document Name	
Comment	
Hydro One still has concerns with the following points regarding Footnote 13: 1) 13c – The term “open circuit” is not clear. Please provide clarification of the term and an example of how it is typically monitored in the supplementary material for better understanding. 2) 13d – We recommend that a single trip coil that is “monitored and reported at a Control Center” be treated the same way that communication systems (Footnote 13b) and DC Supply (Footnote 13c) are treated (to meet the redundancy requirement).	
Likes 0	
Dislikes 0	
Response	
1) There is a NERC Technical Paper dated November 2008 titled *“Protection System Reliability Redundancy of Protection System Elements*” which explains why monitoring an “open circuit” is required. The SAMS and SPCS recommendation from Order No. 754 and Section 1600 data request aligns with most of the elements in the NERC Technical Paper. For reference Figure 5-12 is copied from this technical paper.	

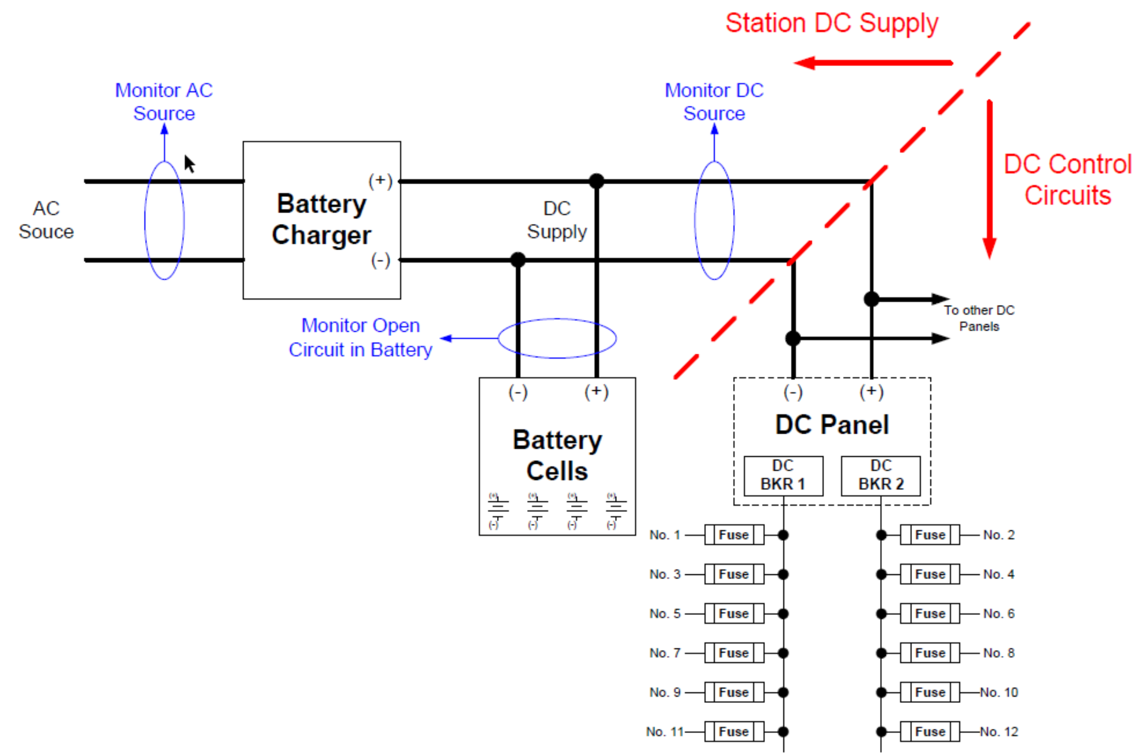

Figure 5–12 — Station DC Supply and Monitoring

2) Monitoring was added to footnote 13d.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	

Comment	
TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments provided by JEA and TVA. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
See responses to Questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5. According to the FERC Order No. 786, there is no direct correlation between the time duration of an outage and system impact. A shorter duration outage may be more impactful to the system than a three-month outage. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-	

month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and 2.4.3.	
Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power	
Answer	No
Document Name	
Comment	

We disagree with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission’s directive from Order No. 786 Paragraph 40.

The clarifications added for entity’s spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission’s directive from Order No. 786 Paragraph 89.

The replacement of the ‘Special Protection Systems’ with ‘Remedial Action Schemes’ is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13. Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments provided by MEAG Power. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
While there are many improvements implemented in this posting, there are still some modifications that should be made as articulated in the responses to the previous questions in this Comment Form, and additionally: Requriement 2, Part 1.5, we suggest modifying the following phrase (see BOLD font for modifying word): "…….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….." to"…….the impact of this possible unavailability on System performance shall be assessed. The **assessment** shall be based on analysis performed for the P0, P1, and P2 categories identified in Table 1…..".	

Part 2.1.3 and 2.4.3 - We propose alternative text for Part 2.1.3 and 2.4.3, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with the **selected** outages modeled in Requirement R1, Part 1.1.2, under those System peak, Off-Peak, **or other** conditions when **the selected** outages are scheduled **or planned to occur**." The System peak or Off-Peak models will normally be suitable for the Part 2.1.3 requirement. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using of other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models. The addition of the word, "planned", allows the inclusion of outages identified by PCs or TPs that are necessary in the planning horizon to implement Corrective Actions Plans – as most if not all are likely not to be scheduled yet. Item h in the first page of Table 1 should be relocated to "after Item e" but before the Steady State section. Then re-alphabetize accordingly. Footnote 14 - We propose adding a **Footnote 14** that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. " Even with the relaxation of required performance, the rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onerous (P8).	
Likes 0	
Dislikes 0	
Response	
1) The language in Requirement R2, Parts 2.1.3 and 2.4.3 has been revised in the newest red-line version of the standard. 2) The latest standard for parts Requirement R2, Parts 2.1.3 and 2.4.3 are significantly different than the prior posting 3) The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

In addition to the issues noted in #2, Texas RE noticed the following:

- In Part 3.4, Texas RE is concerned that allowing registered entities to select which P1 events are "expected to produce more severe System impacts", registered entities have the flexibility to ignore P1 events without determining the actual impact of the events. Texas RE recommends all P1 events should be selected.
- In Table 1, Texas RE noticed P8 is not listed in Steady State Only or Stability Only. Is it the SDT's intent to leave it out of those conditions?

Likes 0	
Dislikes 0	

Response

The language in TPL-001-4 contains the following language for all P1 through P7 and extreme events "…. events in Table 1, that are expected to produce more severe System impacts …". While your statement is true, an entity could ignore some P1 events that are more severe or most severe, changing the standard to require all P1 events will be arduous for some entities. Additionally, this changes was not included in the SAR and the SDT may not have the authority to make this change at this time. Each entity in their selection of the P1 contingencies must have a technical rationale for identifying the P1 contingencies they select. As an RE, you can make recommendations that they revise their technical rationale to include something they are not including at present.

It was the intent of the SDT to require stability to be performed on P8 events. Due to other comments P8 was removed as a planning event and kept as an extreme event.

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

KCP&L recommends the Standard include language that will allow establishing the scope of contingencies in dynamics to a specific area local to the equipment.

Concern

The proposed revisions substantially expand required assessments and studies, including long-lead time equipment into dynamic analysis, and consideration of all outages—without limitation—during the assessment process.

The company recognizes the proposed revisions reflect the Orders' language requiring consideration of outages without limitation, and so forth, but the language to satisfy the Orders require markedly greater resources.

Recommendation

KCP&L suggests adding language that provides an efficiency, or like efficiencies, in the assessment process and addresses the Standard Requirements. We suggest the following:

Requirement language or guidance that establishes the scope of contingencies in dynamics to a specific area local to the equipment. This provides an efficiency in the evaluation of contingencies by allowing the TP to draw a bus-ring around applicable equipment and evaluate contingencies within a smaller, yet relevant, range.

Likes 0	
Dislikes 0	
Response	

The SDT does not have authorization in the SAR to limit the scope of dynamic simulations. The TP/PC can utilize a contingency selection criteria in the technical rationale. The list of stability analysis contingencies can include only those Contingencies where if lost results in more severe impacts to the BES. This language exists in TPL-001-4 and is not being revised by the SDT of TPL-001-5. The FERC directive from Order No. 786 requested "significant" outages be studied with a duration time less than six months. The SDT has difficulty defining "Significant Outages" that work for all entities from the east coast to the west coast. The language "Known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure, or according to a technical rationale …" allows the TP/PC to have a documented procedure or technical rationale which is designed to reduce the list of outages required to be studied. It is up to the TP/PC to determine what "Significant Outages" mean for their system. The language was not intended for the TP/PC to study all outages. For KCP&L, their technical rationale can state "specific areas local to the equipment" that are more critical to KCP&L's portion of the BES. Long Lead Equipment: TPL-001-4 requires steady state studies be performed for items Long Lead Transmission equipment that do not have spares. Adding spare equipment can reduce the need for performing stability studies for these types of equipment. FERC Order No. 786 directed the SDT to add language requiring Long – Lead Equipment without a spare be studied in stability not just steady state. Therefore, the SDT is required to make this revision to the standard.

Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	No
Document Name	
Comment	
National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001, including the creation of the proposed P8 event. We believe that, in particular, Footnote 13 still includes some ambiguity in defining what protection performance is needed to reduce the risk of reliability impact from Single Points of Failures, and would like to provide the following comments:	

Does “spare equipment strategy” mean the existence of at least a single spare for major transmission equipment that has a lead time of more than one year; and does Requirement 2.4.5 imply that the existence of such a spare would eliminate the need to assess the impact of the possible unavailability of such equipment on System performance? If so, then Requirement 2.4.5 should be written this way.

As currently written, Requirement 2.4.5 lacks clarity. Every reasonable “spare equipment strategy” for equipment with a lead time of one year or more could result in the unavailability of such equipment; it is a matter of probability. For example, an Entity with 100 large power transformers could have a spare transformer strategy of maintaining one system spare. However, it is possible that two transformers could fail during time span of one year. With only one spare, the Entity would be exposed to operating the system for up to one year with one less transformer than designed. Even if the Entity has four (4) spares, it is still possible that five (5) transformers could fail during one year (albeit with much lower probability), which would leave the Entity similarly exposed. Greater clarity is required for Requirement 2.4.5, as is more criterion development.

It is not fully clear as to what constitutes “comparable” in the context of comparable Normal Clearing times in Table 1 Footnote 13 Part a. Please also clarify what constitutes an "alternative" relay, beyond allowing for response to non-electrical quantities. What if alternative relay does not provide the same clearing time as the primary relay (e.g., the alternate relay is an impedance relay with longer Zone 2 timer, or the alternative relay is an overcurrent relay, while the primary relay is an impedance relay). Could any relay classified as an “alternative” relay be considered as ‘redundant’, and therefore Footnote 13 would not apply? We would like the SDT to provide guidance on what constitutes “comparable” Normal Clearing times and an “alternative” relay, e.g., in a ‘Guidelines and Technical Basis’ section.

Even after including auxiliary relays and lockout relays, it is still not fully clear what the term “control circuitry” includes. As written, it seems that “control circuitry” (apart from wiring) includes auxiliary relays and lockout relays. Since we believe it could be advantageous to provide a more ‘formal’ definition of this term, we suggest providing additional guidance in a ‘Guidelines and Technical Basis’ section and/or including a definition for “control circuitry” in the ‘Glossary of Terms Used in NERC Reliability Standards’.

As another Entity brought up during the NERC webinar on March 22, 2018, why does the exclusion (provided per Footnote 13 Part b) for communication systems not also extend to single protective relays (referred to in Footnote 13 item a), if monitored or reported at a Control Center?

We also believe it would be of value to consider requesting entities to document the rationale regarding considerations regarding non-redundant components of a Protection System evaluated per Footnote 13.

Likes 0	
Dislikes 0	

Response

The spare equipment language in Requirement R2, Part 2.4 mirrors the language in the TPL-001-4 2.1.5. The SDT does not desire to revise the existing language in Requirement R2, Part 2.1.5. However, clarity on what is meant by the spare equipment strategy is being added to the technical rationale.

The SDT affirms that all parts of footnote 13 has to be either redundant, or monitored (footnote 13 b, c, and d) or studied as a P5 event. The technical rationale is used to develop a contingency list of BES facilities that if lost have a more severe impact to the BES. Once the list of BES facilities are identified all parts of footnote 13 must be evaluated as a P5 event.

The footnote 13 focuses on the components of a Protection System to be considered as having a reliability impact from Single Points of Failures.

Footnote 13a is the only part of the footnote that does not have monitoring. TPL-001-4 P5 is for non-redundant relays. If monitoring were added to footnote 13a, it lowers the bar from where TPL-001-4. There is no desire from the SDT to lower the bar.

Related to “comparable” in footnote 13a, in the context of comparable Normal Clearing, and ‘’alternative’’ relay terms, additional clarity was added to the technical rationale.

The relay classified as an “alternative” relay can be considered ‘’redundant’’, if it is designed with the same performances as the protective relay such as the operating time, selectivity (tripping of the same elements).

If not, the alternative relay, which responds in a delayed clearing time and trips more elements than the protective relay, cannot be considered redundant. Then the P5 event will need to be studied using the delayed clearing time. Any elements expected to be tripped by the alternative relay must be tripped during the P5 simulation.

DC control circuitry includes everything from where the DC supply ends up to and including the trip coils. This includes the wires, auxiliary relays and lockout relays. We agree with the suggestion that additional clarity should be added to the technical rationale.

According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system. Therefore, the protection system design must consider the protective relays exposure to higher risk of failure.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
It is recommended to consider revising Sections 3.2 and 3.5 in a similar manner to the proposed revisions to Sections 4.2 and 4.5. *Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):* Requirement 4.1 states that "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1….." Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1. *Additional Comment for consideration, related to clarification of the Standard:* Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).	
Likes 0	

Dislikes 0	
Response	
Revisions to Requirement R3, Parts 3.2 and 3.5: This is a good suggestion the standard was revised with this change. Revisions to Requirement R4, Part 4.1.1 through 4.1.3: This is also a good suggestion. However, the issue is contained in TPL-001-4. The SDT also feels that adding additional columns to Table 1 will make it very difficult to see on standard printable paper. Related to Requirement R2, Part 2.7: If Table 1 does NOT allow non-consequential load loss and/or interruption of Firm Transmission Service and footnote 12 does not apply, a TP/PC can utilize Part 2.7.3 until a CAP can be implemented. If the non-consequential load loss or interruption of Firm Transmission Service can be done in order to meet the performance requirements and it is allowed in Table 1, then the CAP is required but it could be an operating procedure which identifies the load to drop or transmission service to curtail in order to meet the performance requirements. The NERC Glossary for a CAP can include operations instructions or specific construction of projects.	
Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF and ACES comments and: **13b. Single communications system** • Monitoring a single communication scheme does not provide the same robustness as having a redundant communication scheme. • Communication failures in blocking schemes do not result in delayed clearing. •	

- It is important for planning to identify locations where delayed clearing of faults (such as in zone 2 time) could lead to cascading outages or stability concerns. If faster clearing times are required, these elements should have redundant communications installed. In many companies, these studies are already being performed. If not, the requirement to study the impact of failures of single communication schemes could drive a company to identify where redundant communications are required.

-

- The intent of the standard is to study failures/contingencies which are most impactful to the BES. Typically, single communication schemes are in place to limit damage, improve coordination and as a good design practice. If a communication scheme is installed for these reasons, the “Normal clearing time” of the protective system may not be necessary to maintain system stability or prevent cascading outages.

-

- The use of the phrase “Normal Clearing time” should be changed to “time required to maintain system stability” or “critical clearing time” or “time to prevent misoperation, cascading, or unintentional islanding”. Otherwise, non-redundant communications systems which were not installed for the purpose of maintaining stability would need to be evaluated (or monitored). Such evaluation would be an unnecessary burden.

13c. Single station dc supply

- How common is the monitoring of a battery open circuit condition? FERC Order 754 report says it was not common at the time of the order to have redundant batteries, and it is probably not that common now to have redundant batteries or open circuit monitoring. Without open circuit monitoring, it is possible that a charger might mask an open circuit in the battery. Open circuit monitoring is possible but is not universally applied where there are single batteries.

- FERC Order 754 only applied to 200 kV substations or higher. The number of substations lower than 200 kV without redundant batteries will be substantially higher.

- GRE’s standard design for new 230 kV substations or higher is to install redundant batteries, but we have many existing facilities that have one battery bank with redundant AC supply. Monitoring for open DC supply has not been considered in the past when defining a redundant DC supply.

- Periodic open circuit testing as required by PRC-005 will likely not meet the requirement of open circuit monitoring.

- This requirement seems likely to drive industry to either retrofit existing installations with open circuit monitoring or to install redundant DC supplies. Is this the appropriate place to drive that decision, for a high impact/low risk battery failure? This could be a significant impact, and it appears that this impact may not be fully understood in the context of reviewing this standard.

- Should a risk based approach be considered—an open circuit battery failure is a low risk, high impact event?

13d. Single control circuitry

- As written, this seems to apply to components (coils, auxiliary relays) and wires.

- Verifying where there is single control circuitry could be costly—there are many legacy installations which may not follow present design practices and would require some type of manual review of substation drawings.

- Consider audit evidence for this requirement. Documentation of present design standards which meet the requirement is practical, will it be sufficient?

- A risk based approach to this requirement which limits the review to redundancy of components instead of wires may be practical. The failure rate of wiring is far less than that of components.

Likes 0	
Dislikes 0	

Response

Footnote 13b: The SDT agrees that monitoring does not provide the same robustness as redundancy. However, the SDT is going above the exact recommendation of the SAMS and SPCS report when communications were added to footnote 13. So monitoring was also added since monitoring is allowed for footnote 13 c and d.

The SDT agrees that not all communication failures result in delayed clearing and therefore these would not need to be studied.

The TP/PC is allowed to identify a critical clearing time and that can be given to the protection engineer to ensure that all parts of footnote 13 are meeting at least this critical clearing time. However, the SDT does not want to be so prescriptive in identifying exactly how the TP/PC should run the P5 analyses.

Footnote 13c: Based on comments from industry monitoring of open circuit is not common and can be problematic, but the SDT does not desire to change the requirement. Redundancy of batteries and chargers is a second option if the performance requirements are not met, adding redundancy being the primary option. A NERC Technical Paper dated November 2008 titled *"Protection System Reliability Redundancy of Protection System Elements*". This document explains why monitoring an "open circuit" is required. The following diagram was taken from the referenced document.

Per the FERC Order No. 754 and SAMS/SPCS report from the Section 1600 data request, the SDT believes that the changes to this standard IS the appropriate place FERC has decided to drive the requirement to retrofit existing installations with open circuit monitoring or install redundant DC supplies, in spite of the low probability of failure.

The SDT understands that GREs substations below 200 kV may be impacted by the changes to this standard. However, there is also a lower probability that there exists performance requirement violations at these lower voltage classes.

The SDT does not feel they have the authority to address PRC-005 requirements.

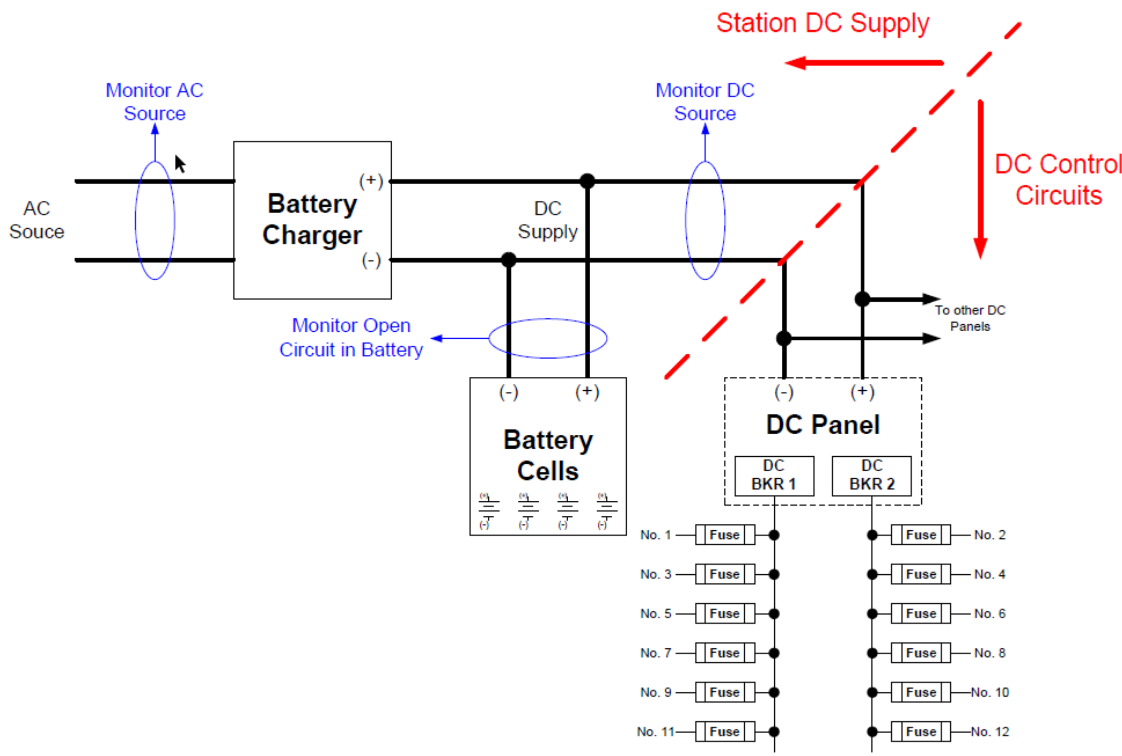

Figure 5–12 — Station DC Supply and Monitoring

The protection experts that the SDT consulted with state that monitoring for "open circuit" can be done without adding to the probability of failure.

Footnote 13d.

- It is correct, the DC control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to everything piece of equipment where the DC supply stops up to and including the trip coils.

- The protection group should be able to identify whether there are single control circuitry.

• For evidence a written notification from the Protection Engineer to the Planning Engineer of which portions of the protection system are or are not redundant. The Planning Engineer via the “technical rationale” can determine what facilities if lost would result in more severe impacts to the BES. The SDT suggests listing the four components of footnote 13 for every location identified by the technical rationale, then the Protection Engineer must look at the protection system at each of these Facilities and identify which have redundancy and give this information back to the Planning Engineer along with the clearing times required to perform the appropriate studies. If redundancy does not exist, then the Planning Engineer needs to perform the studies and determine where redundancy must be added or identify other forms of CAPs. • Monitoring was added to footnote 13d which is intended to make the requirements easier to comply with.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP agrees with the reliability goals of TPL-001-5, but also has some recommendations. SRP recommends moving the final sentence of 3.5. to the end of 3.2., just as was done between 4.5. and 4.2.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees with this suggestion and revision was made.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	

Comment	
See comments from MRO NSRF.	
Likes 0	
Dislikes 0	

Response

Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b
While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

Footnote 13c
The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require "Transmission Owner" be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d
While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Please see Comment #1 and Comment #2	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
Footnote 13, item c lacks clarity as to what constitutes a single station d.c. supply. Typical stations are configured with two components that operate as a single d.c. supply system – an inverter and battery bank. Each of these components provide some redundancy to provide d.c. load for failure of the other component, which could be interpreted as meeting the requirements for a redundant system with no further monitoring required per Proposed Reliability Standard TPL-001-5 Table 1. However, if the entire d.c. supply system is considered a single component, then the requirement to monitor for open circuit is not sufficiently clear to determine if the inverter, battery, or load must be monitored for open circuit. PPL NERC Registered Affiliates requests clarification to Proposed Reliability Standard TPL-001-5 Footnote 13, item c – specifically, as to what constitutes a single station d.c. supply to eliminate ambiguity of the requirement to monitor for open circuit needs.	
Likes 0	

Dislikes 0	

Response

The SDT does not want to list all the elements included in the "single station dc supply". As a minimum it includes the station battery, battery charger and non-battery-based dc supply as defined in the NERC Glossary under "Protection System". A battery charger may not have enough power to open several breakers for a bus differential and causing a protection system not to function if the battery itself fails. The diagram below from NERC Technical Paper dated November 2008 titled *"Protection System Reliability Redundancy of Protection System Elements*" shows how monitoring for both open circuit and low voltage should be done.

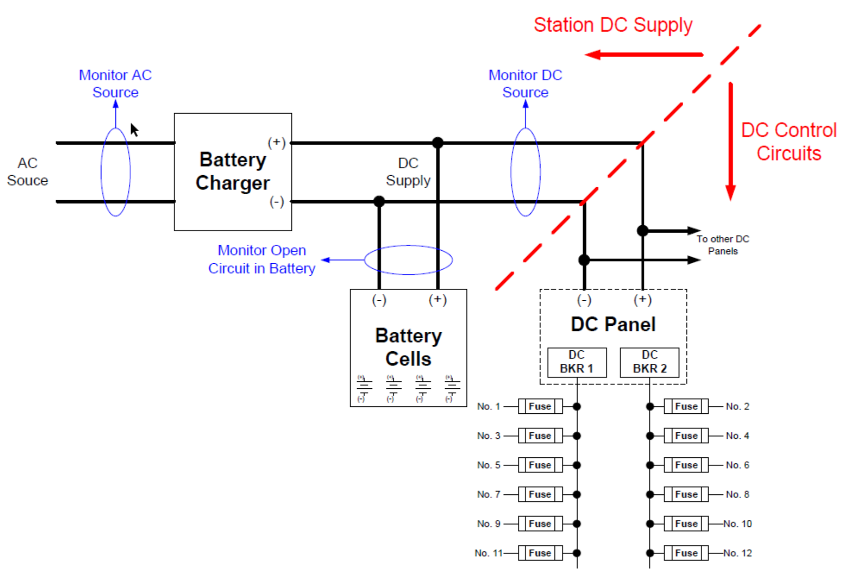

Figure 5–12 — Station DC Supply and Monitoring

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No

Document Name	
Comment	

Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.”

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”.

Same explanatory text as Part 2.1.3.

Table 13, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement. The normally long open circuit monitoring intervals is expected to make the open circuit monitoring exception irrelevant.

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13

components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability. **Footnote 14** - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. "	
Likes 0	
Dislikes 0	
Response	
Requirement R2, Part 2.1.3 and 2.4.3: The language of these two parts were significantly revised. **Footnote 13b** While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP. In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system. **Footnote 13c**	

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require "Transmission Owner" be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

In addition to the comments written above in answer to Questions 1 and 2, FMPA notes that the questions in this comment form do not cover all of the changes. Order 786 required more than just the changes to Requirement 1, part 1.1.2. There is also the addition of Requirement 2.4.5, adding stability analysis as required per an entity's Spare Equipment Strategy. FMPA notes that while studying these events in steady state using P0, P1 and P2 events, doing so for stability doesn't quite make sense. FMPA would support an alternative that simply stipulates that the PA/TP should study which ever Planning event it feels would be the most prudent based on the specific facility(ies) that could be out of service. Many entities do not run P1 events in stability – rather, they simulate other Planning events that, in their engineering judgment, produce more severe system impacts. Thus it doesn't make sense to add P1 events just because a major

facility could be out of service – this may not change the fact that another event such as a P4 or P5 may still be more important to study due to clearing times, and it doesn't really save the entity any time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the language in the FERC Order No. 786 was clear and the requirement to have stability analysis performed for P1 and P2 was part of the FERC Order. The P3-P7 planning events have a lower probability of occurrence and this is likely the reason that they were not included in FERC Order No. 786.	
John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
See Exelon TO Utilities Comments	
Likes 0	
Dislikes 0	
Response	
SDT appreciates your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, SDT has also added a diagram showing the timeline.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	

Comment	
See response to questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	

Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

Same explanatory text as Part 2.1.3.

Table 1, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a. For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires checking dc batteries for the open circuit condition at least every 18 months. Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly shorter than the PRC-005 maintenance requirement. The PRC-005 standard also requires the checking of dc battery voltage levels every 4 months. Finally, the PRC-005 standard requires that "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated." Does the SDT think these timeframes are acceptable? For 13.d, the wording of "single control circuitry" is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability. **Footnote 14** - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES (P8), than the corresponding SLG fault contingency (P5). And only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. "	
Likes 0	
Dislikes 0	
Response	
Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised. **Footnote 13b**	

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP. In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system. **Footnote 13c** The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require "Transmission Owner" be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity. **Footnote 13d** While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d. **Footnote 14:** The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No

Document Name	
Comment	
Manitoba Hydro suggests that R1.1.2.2 be revised as suggested above. The P8 event should be moved to extreme events. The other changes are acceptable.	
Likes 0	
Dislikes 0	
Response	
The language in Requirement R1, Part 1.1.2.2 was revised. The SDT agrees and have removed P8 and made three phase faults an extreme event.	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned." We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions. **Part 2.4.3** - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned". Same explanatory text as Part 2.1.3.	

Table 13, Footnote 13 For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated." Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement. For 13.d, the wording of "single control circuitry" is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability. **Footnote 14** - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. "	
Likes 0	
Dislikes 0	
Response	
Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised. **Footnote 13b**	

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13 d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No

Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require "Transmission Owner" be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d
While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC control circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments provided by JEA and Northern California Power Agency. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	

NVE proposes the following changes for various requirements listed below: **Table 1, Footnote 13d** NVE recognizes the importance of studying the impact of a failure of a single control circuitry, but has concerns with the duplication of component types in this footnote with other planning events. Studying the failure of control circuitry associated with a breaker trip coil would result in a breaker failing to operate for a fault. This is the same effect as a fault plus a stuck breaker. NVE recommends that Footnote 13d be modified to include studying the failure of auxiliary relays and lockout relays. Footnote 10 should be modified to include scenarios of a failure of a single breaker trip coil to operate. **Table 1, Footnote 13c** Wording to this footnote should be changed to match the portion of the definition of Protection System associated with dc supply to ensure that the failure of any component of a dc supply is studied. *A single station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply) required for Normal Clearing….* **R4.2 and R4.5** NVE agrees with the proposed changes to R4.2 and R4.5. Given that the wording and intent of R3.2 and R3.5 is the same as R4.2 anD R4.5, but for different portions of the planning study (steady state vs dynamic), NVE recommends that R3.2 and R3.5 be modified to match R4.2 ans R4.5 to maintain consistency.

Likes 0	
Dislikes 0	

Response
Table 1, Footnote 13d The TP/PC needs to perform studies and then develop CAPs. The SDT agrees that many parts of P5 footnote 13 and with P4 events results in the same study and therefore the same results. However, if the performance requirements are not met, the CAP needs to cover the P4

stuck breaker issue, and any of the P5 things that are not redundant and/or monitored. Therefore the study of a single planning event may be the same for P4 and many parts of a P5 and it only has to be studied once. However, if this study identifies performance requirement violations, the CAP can be very different. An example of a CAP could be: add stuck breaker scheme to the protection system, add a redundant relay, add redundant control circuitry, add monitoring of DC power supply for both open circuit and low voltage, add monitoring of communication-aided protection scheme. All these things could be required to mitigate the issue identified in the single simulation of the planning assessment. A CAP which eliminates just the stuck breaker issue is not good enough. All components of the protection system listed in footnote 13 have to be included in the CAP along with a method of mitigating the stuck breaker performance violation when a P4 has the same clearing time as the P5. All components of the protection system as well as breakers have to be listed in the standard so as not to eliminate portions of the CAP that would be required in the event that a performance requirement violation shows up in the planning assessment. The P4 and P5 components are not listed to identify both what needs to be studied is also intended to ensure that the CAP includes all the necessary items to improve the reliability of the BES.

The SDT is not attempting to list all things which are included in Footnote 13d since there is likely equipment that exists somewhere that will not be on the list. Footnote 13d includes all things between where the DC supply ends up to and including the trip coils, which includes auxiliary and lockout relays, wires everything from a specific point to another specific point.

Footnote 13c:
This is a very good comment and was considered. Since the SDT cannot come up with an exhaustive list that incorporates all things that can exist in the electric grid from the east coast to the west coast, additional language was added to the technical rationale which follows the standard and should be referred when an entity is unclear what is meant by “Single Station DC supply”.

Requirement R4, Parts 4.2 and 4.5:
The SDT agrees with this comment and made the change to the standard.

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	

LADWP doesn not agrtee with the new proposed revisions specifically the new planning event P8 and the changes made to R4.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees and P8 was removed along with adding a 3-phase fault followed by a protection failure is an extreme event.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
OG&E recommends that Table 1, Footnote 13(d) should be revised to allow exceptions for trip coil circuit monitoring as follows: "d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing**, which is not monitored or not reported at a Control Center**. OG&E suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the Commission's directive from Order No. 754, and is consistent with the recommendations from the Joint Report regarding three phase faults.	
Likes 0	
Dislikes 0	
Response	
Footnote 13d: Monitoring was added to footnote 13d.	

Extreme Event: The SDT Agrees with this comment and appropriate changes were made.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
See Question 2 response	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates the comments provided by JEA and Northern California power Agency. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See above comments in Questions 1 & 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Part 2.1.3 - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned." We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.	

Part 2.4.3 - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”.

Same explanatory text as Part 2.1.3.

Table 13, Footnote 13

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement.

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

Footnote 14 - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “

Likes 0	
Dislikes 0	

Response

Requirement R2, Parts 2.1.3 and 2.4.3 are significantly revised.

Footnote 13b: TPL-001-4 P5 is applicable to non-redundant relays and does not allow for monitoring. The SDT does not want to reduce the bar from TPL-001-4 by adding monitoring.

Footnote 13c: The technical rationale containes language clarifying what footnote 13c includes. If interval of monitoring were included, the TO would have to be an applicable entity in the standard. This would go aginast the SAR.

Footnote 13d: The technical rationale includes additional language on what is defined as DC control circuitry. While the SDT agrees that wires have a lower risk of failure, wires are part of the DC control circuitry. In the latest version of the red-line version of the standard, monitoring of footnote 13d was added. Hopefully, this change is more palatable.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would add "Transmission Owner" as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

Footnote 13d
While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to everything piece of equipment where the DC supply stops up to and including the trip coils. FERC directive was to implement the SAMS and SPCS recommendations from Order 754 and section 1600 data request. According to the SAMS and SPCS recommendation from Order 754 and Section 1600 data request and NERC Technical Paper dated November 2008 titled *"Protection System Reliability Redundancy of Protection System Elements*", wiring of the DC controls needs to be included as redundant. The SAMS and SPCS recommendation was in the FERC order requesting changes to TPL-001-4.

Footnote 14: In the latest version of the standard, the P8 event was removed and a three-phase fault followed by a protection failure was made an extreme event.

Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Santee Cooper disagrees with the proposed revisions to TPL-001-4. The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation.	
Likes 0	
Dislikes 0	
Response	
The SDT is following the FERC orders for the revisions recommended. CAPs can include operating guides which are little or no cost. Without more specifics on this comments, the SDT is not able to respond with any more detail.	

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro appreciates the efforts of the SDT in revising TPL-001-5 – Transmission System Planning Performance Requirements. BC Hydro votes "No" and wishes to provide the following comment. ***The proposed amendments scope from Single Point of Failure is very wide, which will apply to the entire bulk electric system i.e. 100 kV and above. Our ballot would have been affirmative if the scope were limited to extra high voltage (360 kV and above), where a single point of protection failure after a fault can trigger a major system disturbance.*** ***Below extra high voltage levels, BC Hydro protection systems are built using principles of good utility protection practices, as described in the ANSI/IEEE standards and guides, to ensure that they have acceptable reliability i.e. clear faults without mis-operating. Our protection systems are largely redundant but still can have a single point of failure, such as where there is a shared breaker trip coil or a single telecom fibre etc. Based on our fifty years of operating experience, there is no known case where a single point of failure in our high voltage protection system precipitated in a major system disturbance event. It is because probability of a single failure (in our redundant high voltage protection system) impacting our system performance is negligible. Yet demonstrating compliance to the proposed amendments will require BC Hydro to redirect our critical resources (financial and people) in identifying single points of failure in our every single high voltage P&C asset, estimate incremental protection clearing time associated with that failure, and then demonstrate acceptable system performance during the event. Instead of redirecting our critical resources to demonstrate compliance to this negligible probability event, BC Hydro will receive higher reliability benefits by continuing to invest our resources in upgrading the aging protection systems.***	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates this comment. The SDT believes that they are following the FERC directive in making the revised P5 applicable to EHV and HV protection systems. TPL-001-4 P5 applicable to non-redundant relay is currently applicable to both EHV and HV. The SDT believes the implementation plan allows for the time it will take including the time to identify the CAPs required.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
Although appreciative of the drafting team's work on TPL-001-5, LES believes the following changes would provide greater clarity within the standard. R2.1.3 & R2.4.3 – Recommend "when known outages are scheduled" be changed to "when known outages **occur**" to provide greater clarity. R2.4.3 – The objective for including known outages in TPL-001-5 should be to ensure that all types of known outages are being reviewed while keeping the burden of additional stability analyses within reason. As currently drafted, the standard would require both steady state and stability analyses for all known outages included in the Planning Assessment. LES recommends modifying the standard to allow steady state analyses and limit stability analyses based on the use of Engineering Judgement in the Transmission Planner's technical rationale for selecting known outages. Recommend changing R2.4.3 to state "…under those System peak or Off-Peak conditions when known outages occur **and have been identified as requiring Stability analysis**". Footnote 13a: To ensure "comparable" isn't mistaken to mean having identical Clearing times, LES suggests revising footnote 13a to instead state "…that provides comparable**, but not necessarily identical,** Normal Clearing times". Footnote 13c: LES recommends removing "open circuit" from Footnote 13c. The absence of open circuit monitoring is too restrictive to consider a single station DC supply as non-redundant. Both a battery charger and battery provide DC supply redundancy because either device can provide DC power if the other device fails or has an open circuit. Additionally, PRC-005 provides adequate testing for open circuits.	
Likes 0	

Dislikes 0	
Response	

Requirement R2, Parts 2.1.3 and 2.4.3:
This language was revised substantially.

Part 2.4.3: The use of a technical rationale to determine the "significant outages" which must be studied is already in the standard. There is nothing in the language that prevents LES, from running a separate set of "significant outage" on stability compared to steady state as long as this is documented in the technical rationale.

Footnote 13a: The SDT has made a clarification about what a comparable clearing time represent for purposes of footnote 13 in Section 4 of the technical rationale.

Footnote 13c: The SDT believes that an open circuit on the DC supply will cause a protection failure so both open circuit and low voltage must be monitored **OR** redundant battery and charger is required if performance requirements of the study are not met. The SDT believes that in some cases like in bus differential protections, the charging system will not have enough current to send a signal to all the trip coils that must be activated. Therefore, the charging system is not sufficient backup for the DC supply. TPL-001 is a standard for identifying studies required in order to plan the system. PRC-005 is a maintenance standard for identifying the maintenance periods. There is no correlation to these two standards.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

In the response to Question 1, we voiced our concerns on the inclusion of P8. Rather than its inclusion, one possible alternative would be to redefine the definition of Delayed Fault Clearing to only include backup protection system with an intentional time delay. A separate term could be created for Breaker Failure Fault Clearing. Note that in the NERC technical paper "Protection System Reliability Redundancy of Protection System Elements" by the NERC System Protection and Control Subcommittee dated January 2009, page 13, the

committee had to clarify the term for the purpose of their paper. Currently, this white paper is the primary source of guidance for this very complex topic. Due to the expansion of non-redundant components included in the proposed draft of the Standard, the terms provided in the NERC Glossary need to be further developed in order to provide clarity for their new application to this standard. As stated in previous comment periods, we believe usage of the word "comparable" within footnote 13a is ambiguous. While we are not completely certain, we suspect the SDT means "less than or equal to" when using this word. If so, it would be preferable to instead state "A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides a clearing time less than or equal to Normal Clearing times;" In both 13b and 13c, using the word "or" within "is not monitored or not reported at a Control Center" may not be consistently interpreted. Any possible confusion might be eliminated by instead using either "not monitored at a Control Center" or "is not monitored *and* not reported at a Control Center" in both 13b and 13c.	
Likes 0	
Dislikes 0	
Response	
The P8 event was removed and a three phase fault remains an extreme event. Additional clarification has been made in the technical rationale around the word "comparable". Footnote 13b and 13c have been modified and a language was added to the technical rationale to clarify what was meant with monitored and reported to a control center.	
Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	

We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates these comments. The answers to your questions are very lengthy for inclusion in this response. There are many added details the SDT put into the technical rationale which follows this standard. There are many times when a P4 and P5 are the same study, however the CAP will need to include mitigations for both the P4 and P5 so both requirements had to be listed in the standard for the reliability improvements that are necessary. There are also times when a P4 and P5 are different. A bus differential protection system is one example where a P4 andP5 result in different studies. Please refer to the technical rationale all answers to your comments. If you still have questions, contact the NERC staff and more language can be added to the technical rationale in order to make it clearer.	
Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
CHPD disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new Planning Event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for Extreme Events and Cascading (keep this section unchanged from the current TPL-001-4 standard).	

In moving the three-phase fault with protection system failure from an Extreme Event to a P8 Planning Event, the SDT has also changed the required performance levels from that of the Extreme Event to those of the planning standard, which creates an undue burden. Also, while the SDT stated in their Consideration of Comments to TPL-001-5 Draft 2 Question 1 “the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement,” the current language of the proposed standard doesn’t clearly state that a CAP isn’t required. CHPD disagrees with these changes. The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate. Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the Joint Report from SPCS and SAMS. The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13. However, CHPD would like to see non-redundant but monitored relays and control circuitry (as defined in Table 1 Footnote 13.a. and 13.d.) have the same exclusion as the monitored communication systems and station dc supplies as allowed in Table 1 Footnote 13.b. and 13.c. for Planning Events P5 and P8. CHPD suggests the SDT restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This adequately addresses FERC’s concern regarding three phase faults from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the CHPD comments and agrees. The P8 planning event was removed and a three-phase fault followed by a protection failure remains an extreme event. Footnote 13 :	

13a: Single point of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system. 13d: The footnote 13d has been modified, and a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant.

Jeff Landis - Platte River Power Authority - 3	
Answer	No
Document Name	
Comment	

PRPA supports JEA comments.

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 subrequirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to

adequately addresses the Commission's directive from Order No. 786 Paragraph 89. The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate. Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure Unofficial Comment Form Project 2015-10 and Single Points of Failure | February 2018 5 in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS. The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13. Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates the comments provided by JEA and PRPA. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No

Document Name	
Comment	

Tri-State does not agree with the language of Footnote 13:

Footnote 13 is weakly worded and suggests that elements of a protection system should be consider rather than shall be studied. Stronger language which clearly defines what components of a protection that are included and what are excluded should be used.

Section D: The standard does not adequately explain the difference between a breaker failing to operating and failure of an element of a protection system resulting in the breaker failing to operate. In most cases, the protection events and post-contingency system states are identical. An addendum or reference to technical documentation which clearly explains the scenarios where they may differ should be included.

Likes 0	
Dislikes 0	

Response

For P5: The first step is the TP/PC must identify a list of Facilities to be studied per the technical rationale. Then in determining the delayed clearing time for completing the studies, components of footnote 13 must be considered. The components with the longest clearing time should be identified to be able to adequately perform the stability portion. When the stability portion is complete, if there are no performance requirement violations then that portion of stability is complete, no CAP is required. If however the performance requirements are not met, then the TP/PC must identify the critical clearing time where the stability analysis meets the performance requirements. All components of footnote 13 that result in a delayed clearing time longer than the critical clearing time must be considered when identifying a CAP. For example, if a failure of a relay and trip coil both result in a delayed clearing time greater than the critical clearing time, a redundant relay AND redundant trip coil will be required in the CAP. Adding a redundant relay alone is not good enough in this example. Since language in the actual standard cannot include many of the details, some details of how to complete the assessment for P5 was put into the technical rationale. The SDT appreciates these comments concerning footnote 13. The SDT has difficulty creating an exhaustive list of exactly what components of a protection system should be included. It is likely that something would get missed when this list would need to apply to all existing protection systems from the east coast to the west coast. The SDT utilized NERC Technical Paper dated November 2008 titled *"Protection System Reliability Redundancy of Protection System Elements"*

which does a better job of defining all the equipment that must be redundant. Language was added to the Technical Rationale which follows the standard. Entities should utilize the technical rationale when developing the portions of a protection system that must be redundant when performance requirements are not met as a result of the study.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
As stated in response to Question 2 above, AZPS recommends that a definitive time period of "more than 3 months" be added to Requirement 1, Part 1.1.2. Please refer to AZPS's comments in response to Question 2.	
Likes 0	
Dislikes 0	
Response	
The SDT does not feel that a time period for outage duration should be used as a means of identifying "significant outages". The SDT believes that a study or test should be used to identify significant outages.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
With the exception of clarification for R1.1.2.2 and the P5/P8 suggested change, BPA is in agreement with the other revisions.	
Likes 0	
Dislikes 0	
Response	

The P8 was removed and the three-phase fault remains an extreme event. The language in Requirement R1, Part 1.1.2 has been revised(deleted) in the proposed draft and we are hoping this is more acceptable to BPA.	
John Seelke - LS Power Transmission, LLC - 1	
Answer	No
Document Name	
Comment	
See thw response to Q2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	
We agree with the conforming revisions specifics but we do not agree with additional modifications.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT cannot respond to this comment without something more specific to the comment.	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	

Answer	No
Document Name	
Comment	

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately

address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
The SDT appreciates the comments provided by JEA. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The proposed change to requirement R1, part 1.1.2 to eliminate the six month minimum duration requirement for considering known outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 Operational Planning Assessments. Removing the six month threshold also adds a considerable burden on the annual Planning Assessment without providing significant value by requiring studies be performed for short term maintenance outages in the Planning Horizon. The annual TPL-001-4 Planning Assessments represent projected system conditions in the near-term and long-term planning horizons and are not meant to identify operational concerns for outages shorter than six months. The system models used in the Planning Assessment represent a general snapshot of stressed system conditions with all facilities in-service. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing. In addition, the information regarding planned outages occurring beyond year one of the near-term planning horizon would be expected to be limited or unavailable as most outages are scheduled within two months of the requested outage time. For these reasons, outages shorter than six months are more accurately addressed in the operations planning horizon, when more information is available regarding overlapping outages and current system conditions.	

Planned outages are considered in Operational Planning Assessments. T**he IRO-017 standard establishes the outage coordination process** within the operations planning horizon, which covers the period from day-ahead to one year out. The outage coordination process includes development and communication of outage schedules, evaluating impacts and developing operating plans to mitigate outage conflicts, or rescheduling outages when necessary in order to reduce the reliability impact of the critical outage. This process ensures a more accurate modeling of expected system conditions, including information on concurrent outages.	
Likes 0	
Dislikes 0	
Response	
IRO-017 R4 requires coordination of the RC and TP/PC related to outages in "Time Horizon: Long-term Planning", while the Operations Planning is in the "Time-Horizon: Operations Planning". The SDT does not feel that there is an overlap due to the "Time Horizon" as written in IRO-017. Due to FERC Order No. 786, outage duration alone should not be used to determine significant outages. The SDT feels that a test or study should be used to determine significant outages. This test or study should be documented in a technical rationale. Similarly, TOP-003 operational studies are performed in the Operations Planning Time Horizon. So without TPL-001-5, at present the SDT believes there is a gap in being able to complete the requirements of IRO-017 Requirement R4. The FERC Order No. 786 required the language in TPL-001-4 Requirement R1 be revised to include outages with a shorter duration than six months. The test or study documented in the technical rationale can be used to identify a smaller list of "Significant Outages" to make this manageable. The TP/PC has a list of projects required as a result of the planning assessment in the Near-Term Transmission Planning Horizon. The TO should know what outages are required in order to build the projects that the TP/PC identified in the planning assessment. A MOD-032 data request can be used by the PC to identify the lists of outages that could occur in the Near-Term Transmission Planning Horizon.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes

Document Name	
Comment	

Table 1, Footnote 13 – The ability to monitor the status of a Protection System Component does not fully mitigate the risk of the failure of a non-redundant component. The exception of 13b is not consistent with the requirements for redundancy in protective relays, even though the components can be very similar in design and performance.

For 13.b, consider removing the qualification, “which is not monitored or reported within 24 hours at a Control Center”. If the SDT believes the qualifications for monitoring and reporting are valid for the communication channel for a communications based relay scheme and elects to leave this, then ITC would only then suggest to add the same “which is not monitored or reported within 24 hours at a Control Center” qualification to 13.a . ITC, however, believes the better wording for the standard is to not have this gualification in either 13.a or 13.b.

Likes 0	
Dislikes 0	

Response

Footnote 13 is not attempting to define what a redundant protection system is for other NERC standards. Footnote 13 is only for TPL-001-5 assessments. In Footnote 13 a risk based approach was considered and consisted to classify the component with higher/ lower risk of reliability impact from Single Points of Failures as mentioned in Footnote 13a to 13d.

Even if monitoring is not equal to redundancy, for lower risk of reliability impact components (based on NERC 2014 analysis), the monitoring is considered sufficient and will allow excluding the associated components from P5 event study.

TPL-001-4 P5 event is applicable to non-redundant relays and does not allow for monitoring. The SDT does not want to reduce the bar from TPL-001-4 by adding monitoring. A single point of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design.

According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system. Therefore, the protection system design must consider the protective relays exposure to higher risk of failure. Thank you for this comment.	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
We do however propose the following improvements : • Requirement 2.5 addresses "material generation additions or changes". These additions or changes should already have been included in the model as per (renumbered) R1.1.3. Thus 2.5 is superfluous. However if SDT retains this requirement, it should also address other material additions or changes such as load increase or relocation. • Requirement 2.7.1: Examples should not be in a requirement, they should be moved to guidance. • Replace « assessment » in requirements 3.3.1.1 and 4.3.1.2 with « Planning Assessment »	
Likes 0	
Dislikes 0	
Response	
These issues exist in TPL-001-4 and the SDT does not feel that they have the authority to fix the items in the prior standard that was not included in the SAR.	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes

Document Name	
Comment	
Requirement 2.4.3 has been added to TPL-004-4, which caused the Requirement previously identified as 2.4.3 to be renumbered to 2.4.4. Therefore, in the second to last sentence where a reference is made to Requirement 2.4.3, the reference needs to be changed to 2.4.4.	
Likes 0	
Dislikes 0	
Response	
Thanks for this comment. This has been addressed and corrected.	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	
While OUC agrees with the addition of P8, OUC believes clarity needs to be added to Requirement 1 in order to avoid the TPL-001-5 standard overlapping with Operations Planning, and believes an outage duration would be an appropriate way to filter outages of less significance that Operations Planning would otherwise be assessing day-to-day.	
Likes 0	
Dislikes 0	
Response	
Due to industry comments, P8 was removed and the three-phase fault followed by a protection failure will be in extreme event. Changes were made to Requirement 1 related to known outages. IRO-017 Requirement R4 requires coordination of the RC and TP/PC related to outages in “Time Horizon: Long-term Planning”, while the Operations Planning is in the “Time-Horizon: Operations Planning”. The SDT does not feel that there is an overlap due to the “Time Horizon” as written in IRO-017. Due to FERC Order No. 786, outage duration alone	

should not be used to determine significant outages. The SDT feels that a test or study should be used to determine significant outages. This test or study should be documented in a technical rationale.	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
We generally agree with the changes, except for R1.1.2.1 as noted above. Also, Is there a need to consider a three-phase fault on a shunt device with a stuck breaker resulting in Delayed Fault Clearing? (See Table 1 Stability Extreme Events) It appears this item is missing.	
Likes 0	
Dislikes 0	
Response	
The known outages in Requirement 1 was removed, but studies related to known outages was revised. Related to Table 1 Stability Extreme Event comment: This may have been an oversight from the SDT for TPL-001-4. However, the SAR does not allow the SDT of TPL-001-5 to correct potential issues of TPL-001-4.	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
The following questions/requests were previously submitted; however, Tacoma Power is not clear about the drafting team's responses. 1. If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An	

entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6. 2. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply.	
Likes 0	
Dislikes 0	
Response	
1. The SDT cannot and should not comment on PRC-005. 2. The control circuitry begins where the DC supply ends. There are diagrams that may be helpful contained in the technical rationale.	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
We can agree with the changes, notwithstanding our response regarding Requirement 1, Part 1.1.2. The standard drafting team should revisit Requirement 1, Part 1.1.2.1. if the ballot does not pass.	
Likes 0	
Dislikes 0	
Response	
The known outages in Requirement R1, Part 1.1.2 was removed, but studies related to known outages was revised.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	

It is recommended that for P5 and P8 events in Table 1, the Drafting Team consider modifying the phrase "Fault plus non-redundant component of a Protection System failure to operate" to "Fault plus single component of a Protection System failure to operate" and modifying the phrase "Delayed Fault Clearing due to the failure of a non-redundant relay component of a Protection System protecting the Faulted element to operate as designed" to "Delayed Fault Clearing due to the failure of a single component of a Protection System protecting the Faulted element to operate as designed". Similarly, note 13 in Table 1 might be modified to read "For purposes of this standard, failure of a single component of a Protection System is considered to be as follows". It is suggested that this language might describe the same event a bit clearer, and in a way consistent with the description of similar failure for RAS as described in PRC-012-2. This would avoid any potential debate over the definition of redundancy - in order to determine what is a "non-redundant" component, one needs to define what does and does not constitute redundancy in this context (e.g., What about a backup relay that performs similar functions, but is not exactly the same? What about a duplicate relay with slightly different settings, or configured in the system in such a way that it responds a little slower? What if there is a "redundant" trip coil in a breaker, but it's not hooked up?). It would also clarify that for the case of multiple non-redundant components in a particular Protection Scheme, that the simultaneous failure of all non-redundant components is required to be considered (we assume the intent in such a case would be to consider failure of each non-redundant component one at a time).

As provided in previous comments periods, Exelon recommends removing communication systems from footnote 13 in the revised standard. The SPCS concluded that the analysis of communications systems with regard to single points of failure did not pose enough of a risk for inclusion in footnote 13. As noted in the "Consideration of Comments", the SDT "augmented the SAMS/SPCS recommendations to include the reference to the subset of communications systems that are part of a communication-aided Protection System". By doing this, the inclusion of communications systems extends beyond the scope of the SAR to "[c]onsider the recommendations for modifying

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report." Requirement R2.7 should be revised to reference Requirement R2, Parts 2.1.4 and 2.4.4 and not Requirement R2, Part 2.4.3 based upon the currently proposed draft. Requirement 2.4.4 is specific to the sensitivity studies. The SDT should consider aligning the language in Requirements R3, Part 3.5 and R4, Part 4.2: "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."	
Likes 0	
Dislikes 0	
Response	
The SDT removed the P8 event and a three phase fault followed by a protection failure remains an extreme event. The SDT feels that the suggested language changes to Table 1 appear to make less clarity instead of adding clarity. The SDT added a significant amount of clarity in the technical rationale for what is redundant and what is not redundant for purposes of TPL-001-5 only. The SDT members are not sure what is meant in this comment by the simultaneous failure of all non-redundant components of a protection system. The TP/PC can consider the components one at a time and this potentially means four simulations. Or the TP/PC could consider studying the worse delayed clearing time and discuss with the protection group which parts of footnote 13 cause performance criteria violations. The task is to determine which components of Table 1 footnote 13 are redundant (meaning backups have the same clearing time) or are monitored. If monitored or redundant for footnote 13b, c and d and redundant for footnote 13a, then no P5 stability simulations are required at this location. If they are required for simulation (not redundant and not monitored), then a determination of whether it meets performance requirements is done. If performance requirements are not met, then the CAP could be four things: Example of the four things in the CAP at the same location could be redundant relay, redundant DC control circuitry, redundant DC supply and redundant communications.	

The addition of communication systems was discussed extensively and while it is true, the SAMS and SPCS report did not include this particular recommendation, the SAMS and SPCS report did contain a potential risk. The SDT attempted to minimize the impact of adding communications by also allowing it to be monitored or redundant.

The SDT made changes to Requirement R2, Parts 2.1.4, 2.4.4, Requirement R3, Part 3.5 and Requirement R4, Part 4.2 which we feel satisfies your comments to this portion.

5. *Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?*

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to #4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters	
Answer	No
Document Name	
Comment	
Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not	

disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754. **Suggestion**: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**.	
Likes 1	JEA, 5, Babik John
Dislikes 0	
Response	
Thank you for your comment; The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.	
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6	
Answer	No
Document Name	
Comment	
These are not cost effective because it will create additioanl studies that will have minimal to no benefit for planning purposes.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT understands the significant work introduced by the TPL-001-5 changes and has allowed sufficient lead time to complete the work as outlined in the Implementation plan.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA feels that it is not cost effective to plan and construct a project for a planned outage of short duration that would be coordinated ahead of time according to outage planning processes (development of an operating plan) and would not be planned during peak seasons. It would also not be cost effective to plan and construct a project for a planned outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.	
Kelsi Rigby - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

AZPS notes that it believes that, with the exception of Requirement 1, Part 1.1.2, the proposed TPL-001-4 is cost effective. As stated in response to Question 2 above, AZPS recommends that a definitive time period of "more than 3 months" be added to Requirement 1, Part 1.1.2. The inclusion of outages that are 3 months or less creates unnecessary study burden with little or no added reliability benefit and the currently proposed criteria increases the potential for inconsistency relative to planning assessments, which inconsistency increases costs while eroding the overall reliability benefit anticipated. Please refer to AZPS's response to Question 2 for additional details.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	No
Document Name	
Comment	

Absolutely NOT. The SDT has not presented a solid cost effective analysis on the proposed changes leaving industry seriously questioning the process and the amount of work that would be potentially created by these changes and the minimal return on investment.

ADDITIONAL COMMENTS

1. In reviewing the edits to R1.1.2, I'm still concerned about the vagueness of those outages that must be modeled and whether such consultation will now require the RC to meet with each TP and PC separately within the FRCC on an annual basis.

2. Given the changes to requirement R1.1.2, we believe there needs to be applicability in the standard to the Reliability Coordinator and not just the PC and TP. Also, since the SDT struck out the duration of six months in R1.1.2, there should be a time-frame around the length of transmission outages given some outages are only for a few hours, some for a day, a week, a month, etc., that may not be covering the year, season, or load level entities are assessing. (3) Regarding the edits to R1.1.2, what happens if the RC, TP, or PC disagree as to which outages to include in the System models? Is it acceptable to the SDT if procedures are written whereby not all entities are in agreement with which outages to include? (4) In R2.1.5, the SDT changed "studied" to "assessed". Can the SDT provide background on what is now expected with the term "assessed" differently than what was performed under the term "studied"? (5) In R2.4.5, can the SDT elaborate on what is expected in, and how detailed, an entity's spare equipment strategy should be that is needed for TPL-001-5? (6) In R2.4.5, the wording "The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment" opens entities up to major compliance interpretation issues as it's not certain that entities will evaluate ALL conditions that the System is expected to experience in our Planning Assessment, this needs to be further clarified by the SDT. (7) P5, and footnote 13, was modified to cover non-redundant components of a Protection System. This is a substantial additional burden onto entities. Seminole requests the team to perform a cost effectiveness study concerning these additional edits. (8) In the Cost effectiveness Document updated(3/8/2018), pg 3 Footnote 13-(2 single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), How is this not a single point of failure?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment; Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known	

outages to be modeled based on the accompanying factors outlined in the TPL-001-5. The SDT has added language to Footnote 13 for clarity and also the technical rationale provides additional details related to your comments. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

Jeff Landis - Platte River Power Authority - 3	
Answer	No
Document Name	
Comment	
PRPA supports JEA comments. Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754. Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
The P8 event creates a major burden to entities to mitigate Extreme Events. This is not cost effective due to the rarity of events and the added reliability benefit is marginal compared to the cost, logistics, coordination and the aggressive implementation schedule needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. CHPD is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754. Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, CHPD recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

Fred Frederick - Southern Indiana Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
The proposed revision is potentially not cost effective depending on the clarification requested in question 4. We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates these comments. Please refer to the SDT response to your question 4 and also the technical rationale provides additional details related to your comments.	

Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	

The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. CAPs can include operating guides which are little or no cost. Without more specifics on this comments, the SDT is not able to respond with any more detail.

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	

Comment
Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry. If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may

lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment; The SDT has added language to Footnote 13d for clarity and also the updated technical rationale provides additional details. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1 and. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
NIPSCO agrees with JEA comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to JEA comments.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	

See JEAs response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to JEA comments.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which is not required by Order No. 754. Because P8 events are considered to be rare occurences in the industry, requiring a CAP is not a effective use of resources. The following conclusion statement in the Joint Report on Order 754 supports this position: "This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5". *See Order 754 Assessment at p. 11.*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events).	

faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
LADWP does not agree with majority of the change. There is no evidence that the changes will be more cost effective. Unitl the new proposed is agreed and approved, it would be hard to made a comment on this question.	
Likes 0	
Dislikes 0	
Response	
The SDT is addressing directives as ordered by FERC for the revisions recommended. Without more specifics on this comments, the SDT is not able to respond with any more detail.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to JEA comments.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	
Comment	

MEC supports NSRF comments. In addition, the zero defect compliance work to maintain perfect protection system drawings and change management is significant with little additional actual system reliability gain due to the rare probability of a delayed cleared fault combined with a single-point-of-failure protection component failure that isn't already known. NERC and industry should work together to seek a better risk based strategy to focus on important substations. Examples could be the use of voltage class levels similar to FAC-003 (200kV and above or as identified by the RC / PA), high fault current levels similar to PRC-002, or number of transmission interconnections similar to the FERC Order 754 effort.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan.

Also please refer to the SDT’s response to NSRF comments.

Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT has added language to footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	

Comment

The changes are forcing the industry to invest to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP/PC to decide whether mitigating possible Casading is cost effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	No
Document Name	
Comment	
No, Although the drafting team has identified "adding redundant protection improves the relialbity of the Bulk Power System at lower costs than other contructions projects" there exists significant costs for associated component of the protections system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has	

allowed significant lead time to complete the work as outlined in the Implementation plan. Without more specifics on this comments, the SDT is not able to respond with any more detail.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a "non-redundant control circuitry" requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry. If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added language to Footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

1. The required analysis of all scheduled outages in the near term horizon is not cost-effective, as it will result in many studies being run without meaningful results and/or with time spent "proving the negative".

2. Introducing a new type of event in Planning Event P8 creates unnecessary compliance burden and is illogical. Furthermore, it opens up industry to additional illogical changes to a planning standard that was generally working pretty well before these changes.

3. Flatly requiring P1/P2 events be studied in stability is likely to simply create busy work since an entity may (not a guarantee – based on details specific to each facility and engineering judgment) determine that a P4 or P5 is more appropriate to simulate, but would be required to run the P1 or P2 event regardless (e.g. in addition to those events the entity feels are best to study).

Likes 0	
Dislikes 0	

Response

Thank you for your comment/ The SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry. If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has added language to Footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No

Document Name	
Comment	
See comments from MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to MRO NSRF comments.	
Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski	
Answer	No
Document Name	
Comment	
GRE agrees with the MRO NSRF and ACES comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to MRO NSRF comments.	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	No
Document Name	
Comment	

To determine if something is cost-effective, the analysis must consider alternatives to achieve a measurable outcome.

The FERC directives are narrowly drafted without significant alternatives to fulfill their outcomes. Reflected in the proposed revisions and Implementation Plan are the directives' narrow framework and, as such, a meaningful analysis of the revisions and Plan's cost-effectiveness is indeterminable.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. Without more specifics on this comments, the SDT is not able to respond with any more detail.

Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name MEAG Power

Answer	No
Document Name	
Comment	

Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. We do not disagree

with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754. Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, Rrecommend NERC survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment; The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment; Please refer to the SDT's response to JEA comments.	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	No
Document Name	
Comment	
The proposed revisions to this Standard would add significant resource and financial burden to TOs and GOs. Recommend for the SDT to evaluate System performance issues thru planning studies prior to making Corrective Action Plans (CAPs) mandatory in the Implementation Plan. This would provide time for the SDT to evaluate the impact and cost implications that these new Requirements have on industry. After an evaluation is done, then the SDT can determine what CAPs would be required and reduce the financial impacts to industry by utilizing a separate Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment; the SDT understands the significant work that would be required to investigate and identify "non-redundant" components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
SCE submitted comments regarding the cost-effectiveness of the proposed revisions to TPL-001-4 during a previous period. SCE's opinion has not changed and, consequently, SCE would like to reiterate our feedback from the previous comment period (i.e., the comment period ending 10/23/2017).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made revisions to footnote 13d. Please see the proposed draft.	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
1. We believe a more cost effective way approach to meeting the FERC directives exists. The proposed changes should allow registered entities the flexibility to determine how they will address this BES reliability risk. The currently proposed solution requires a registered entity to conduct a duplicative contingency analysis for a three-phase fault that is less likely to occur than a single-phase-to-ground fault under similar conditions. 2. The “dc supply” reference to open circuit within Footnote 13c could require an entity to purchase additional equipment based on the accepted configuration. We recommend revising the footnote to only consider when the dc supply is not monitoring or reporting abnormal DC voltages. 3. We thank you for this opportunity to comment.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment; Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. With respect to Footnote 13c, the SDT concluded that single station dc supply that is not monitored or not reported at a Control Center for both low voltage and open circuit should be considered as non-redundant components of a Protection System.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which are rare occurences in the industry and not required by Order No. 754.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

City Light supports JEA comments.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
As proposed, the revisions are overly-complicated and will require a considerable amount of additional work for defining, modeling, and analyzing new contingencies. Further, if corrective actions are required for the proposed P8 event, there is little real payback due to the extreme unlikelihood of the event.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. the SDT understands the significant work that would be required to investigate and identify "non-redundant" components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No

Document Name	
Comment	

There is some correlation between FERC directives in Order NO. 786 and Order No. 754 such as a Tranmission Planner assessing their portion of the Bulk Electric System (BES) for locations at which a three-phase fault accompanied by a protection system failure could result in a potential reliability risk (Order No. 754) and the expansion on Protection System Failures versus Relay Failures (Order No. 786). However, EEI summarized it best by stating in Order No. 786 (p. 46), "...expanding planning studies to include all manner of protection system failures could create a scenario where planners would have to conduct unlimited and unbound studies."

The potential for unlimited studies to include all manner of protection system failures is not a cost effective way of meeting both FERC directives. This new revision expands the purview from relay failure to failure of all protection system components. Additionally, this requirement (and its predecessor) required assessments of entire system unlike the limited ones per FERC order 754.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify "non-redundant" components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

Teresa Cantwell - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	

See comments in response to question 2. The development of a contingency set with acceptable system adjustments would be more efficient than requiring seperate cases be developed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the revisions in the next posting.	
Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hasan Matin - Orlando Utilities Commission - 2 - FRCC	
Answer	Yes
Document Name	
Comment	

OUC would recommend providing some guidelines in order to guide the discussion on how to solve issues found under new Planning Event 8, such as recommending Zone 2 or Zone 3 protection where applicable (if acceptable though testing) or the addition of dual and separate DC sources. Guidelines on what actions to take and when to take them (along with cooridinating these upgrades with the company's protection group) would help further keep the revisions cost-effective by providing a methodology of least cost options to higher cost options.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Yes if the clarification to Requirement 1, Part 1.1.2 is made	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity.	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment the SDT has updated the Implementation Plan to provide further clarification.	
Robert Ganley - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
While the proposed revisions to TPL-001-4 along with the Implementation Plan may be a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754 in terms of corrective action plans, the proposed revisions will present a very significant burden on Planning and Engineering staffs to investigate and identify "non-redundant" components of a Protection System. This incremental burden will have adverse cost impacts.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.	
Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Seelke - LS Power Transmission, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1, Group Name National Grid	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Hydro One, NYISO and Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No comment or opinion on cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	

Answer	
Document Name	
Comment	
No response or comments.	
Likes 0	
Dislikes 0	
Response	

Comments received from APPA

Questions

1. Do you agree with the creation of the proposed P8 event?

☐ Yes
x☐ No

Comments: APPA concurs with the JEA comments that the addition of the P8 event is beyond what was in the Standards Authorization Request (SAR).

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

y☐ Yes
☐ No

Comments:

3. Do you agree with the proposed implementation plan?

☐ Yes
x☐ No

Comments: APPA believes the 36 month period for the proposed standard to be effective is appropriate as is the 24 month period for development of the CAP. However, we do endorse the overall implementation plan and support the reasoning for that lack of support provided in JEA's comments. Similarly, we support the JEA suggestion to remove the proposed P8 event and its associated CAP and seek industry feedback on a more feasible implementation plan.

4. Do you agree with the proposed revisions to TPL-001-4?

☐ Yes
x☐ No

Comments: APPA believes that the proposed revisions to TPL-001-4, especially the inclusion of P8 is not workable and supports the JEA comments and suggestions.

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

☐ Yes
x☐ No

Comments: APPA believes the proposed revisions and implementation plan will not result in a cost effective way to meet the FERC directives in Order No. 786 and Order No. 754. The inclusion of event P8 is the driver for increasing the costs of the proposed standard. Importantly, the increased costs are not commensurate with a material improvement in reliability.

Public power endorses the JEA comments and suggestions.

End of Report

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 MOD-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. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

1.1.5. 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 its 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. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning coordinator or Transmission Planners's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 2.1.3 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 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.

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. 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.

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.

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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5. 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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR	

Version	Date	Action	Change Tracking
		proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Version	Date	Action	Change Tracking

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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. 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:

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communications system that is both monitored and reported at a Control Center shall not be considered non-redundant); c. A single station dc supply associated with protective functions required for Normal Clearing (except a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit shall not be considered non-redundant); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (except a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant).

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.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**
2. **Number:** **TPL-001-~~4~~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:** 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~~
- ~~P4-1 through P4-5 (above 300 kV)~~

- ~~P5 (above 300 kV)~~

~~B. Requirements~~

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 MOD-~~010 and MOD-012 standards~~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) with a duration of at least six months.~~

~~**1.1.3.**~~**1.1.2.** New planned Facilities and changes to existing Facilities.

~~**1.1.4.**~~**1.1.3.** Real and reactive Load forecasts.

~~**1.1.5.**~~**1.1.4.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.6.**~~**1.1.5.** 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 ~~there~~ its 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.**~~**2.1.3.** 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning coordinator or Transmission Planners’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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 ~~studied~~assessed. The ~~studies~~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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

~~2.4.4.~~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, Part2.6 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~~3 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 ~~&~~and 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.~~

~~**M1.**~~**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~~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. 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.

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5. 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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR	

Version	Date	Action	Change Tracking
		proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Version	Date	Action	Change Tracking

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~e.~~ i. 3Ø internal breaker fault. ~~f.~~ 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. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows:
    a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
    b. A single communications system associated with protective functions~~ or types: pilot (#85), distance (#21), differential (#87), current (#50, 51,~~, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communications system that is both monitored and ~~67),~~reported at a Control Center shall not be considered non-redundant);
    c. A single station dc supply associated with protective functions required for Normal Clearing (except a single station dc supply that is both monitored and reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~and open circuit shall not be considered non-redundant);
    d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (except a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant).

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.

~~C. Measures~~

~~M2.~~ ~~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, 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.~~

~~M3.~~M1. ~~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.~~

~~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 R3.~~

~~M5.~~M1. ~~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.~~

~~M6.~~M1. ~~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.~~

~~M7.~~ ~~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.~~

~~M8.~~ ~~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.~~

~~M9.~~M1. ~~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.~~

~~D. Compliance~~

~~1. Compliance Monitoring Process~~

~~1.1 Compliance Enforcement Authority~~

~~Regional Entity~~

~~1.2 Compliance Monitoring Period and Reset Timeframe~~

~~Not applicable.~~

~~1.3 Compliance Monitoring and Enforcement Processes:~~

- ~~Compliance Audits~~
- ~~Self-Certifications~~

~~Spot Checking~~

- ~~Compliance Violation Investigations~~

~~Self-Reporting~~

- ~~Complaints~~

~~1.4 Data Retention~~

~~The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.~~
- ~~The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.~~

~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.~~

- ~~The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.~~
- ~~The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.~~
- ~~The current, in force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.~~

~~The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.~~

~~If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.~~

~~1.5 Additional Compliance Information~~

~~None~~

2. ~~Violation Severity Levels~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.~~	~~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 standards and other sources, including items represented in the Corrective Action Plan.~~
~~R2~~	~~The responsible entity failed to comply with Requirement R2, Part 2.6.~~	~~The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.~~	~~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.~~	~~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.~~
~~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.~~	~~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.~~	~~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 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.~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
		~~OR~~ ~~The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.~~	~~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.~~	~~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 base its studies on computer simulation models using data provided in Requirement R1.~~
~~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.~~	~~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~~ ~~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 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~~ ~~The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.~~	~~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~~ ~~The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.~~
~~R5~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.~~
~~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.~~

	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~**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.~~
~~**R8**~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion.~~ ~~OR,~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.~~	~~The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.~~ ~~OR~~ ~~The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.~~ ~~OR~~ ~~The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request.~~ ~~OR~~ ~~The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.~~

~~E.A. Regional Variances~~

~~None.~~

~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~0~~	~~April 1, 2005~~	~~Effective Date~~	~~New~~
~~0~~	~~February 8, 2005~~	~~BOT Approval~~	~~Revised~~
~~0~~	~~June 3, 2005~~	~~Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2~~	~~Errata~~
~~0~~	~~July 24, 2007~~	~~Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.~~	~~Errata~~
~~0.1~~	~~October 29, 2008~~	~~BOT adopted errata changes; updated version number to "0.1"~~	~~Errata~~
~~0.1~~	~~May 13, 2009~~	~~FERC Approved – Updated Effective Date and Footer~~	~~Revised~~
~~1~~	~~Approved by Board of Trustees February 17, 2011~~	~~Revised footnote 'b' pursuant to FERC Order RM06-16-009~~	~~Revised (Project 2010-11)~~
~~2~~	~~August 4, 2011~~	~~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.~~	~~Project 2006-02 – complete revision~~
~~2~~	~~August 4, 2011~~	~~Adopted by Board of Trustees~~	
~~1~~	~~April 19, 2012~~	~~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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.~~	

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~3~~	~~February 7, 2013~~	~~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.~~	
~~4~~	~~February 7, 2013~~	~~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.~~	
~~4~~	~~October 17, 2013~~	~~FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).~~	
~~4~~	~~May 7, 2014~~	~~NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.~~	~~Revision~~
~~4~~	~~November 26, 2014~~	~~FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.~~	

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 fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee authorized Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal comment period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017
45-day formal comment period with initial ballot	February 23 – April 23, 2018

Anticipated Actions	Date
45-day formal comment period with additional ballot	July 2018
10-day final ballot	October 2018
Board adoption	November 2018

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

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

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System 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 MOD-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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:~~

~~**1.1.2.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and~~

~~**1.1.2.2.** Does not exclude known outage(s) solely based upon the outage duration.~~

~~**1.1.3.**~~**1.1.2.** New planned Facilities and changes to existing Facilities.

~~**1.1.4.**~~**1.1.3.** Real and reactive Load forecasts.

~~1.1.5.~~1.1.4. Known commitments for Firm Transmission Service and Interchange.

~~1.1.6.~~1.1.5. 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~~ its 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 expected to produce more severe System impacts on its portion of the BES, 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.~~2.1.3. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning coordinator or Transmission Planners's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6. 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 expected to produce more severe System impacts on its portion of the BES, 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.**~~**2.4.3.** 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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~~3 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 Schemes.
- 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. 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.

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. 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.

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

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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5~~6~~.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5~~6~~.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5~~6~~.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5~~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.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
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.	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~~8~~) 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.	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 P~~8~~7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	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~~8~~) 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 base its studies on computer simulation models using data provided in Requirement R1.
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.	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~~8~~) in Table 1. OR	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~~8~~) in Table 1. OR	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~~8~~) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR	

Version	Date	Action	Change Tracking
		proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

Version	Date	Action	Change Tracking

Table 1 – Steady State & Stability Performance Planning Events
Steady State & Stability ~~(P0 through P8 events)~~: 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 ~~(P0 through P7 events 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 ~~(P1 through P7 events only)~~:** j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes
~~**P8**~~ ~~Multiple Contingency~~ ~~*(Fault plus non-redundant component of a Protection System failure to operate)*~~	~~Normal System~~	~~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~~	~~3Ø~~	~~EHV, HV~~	~~Yes~~	~~Yes~~

<table>
<tr><th colspan="2">Table 1 – Steady State & Stability Performance Extreme Events</th></tr>
<tr><td colspan="2">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.</td></tr>
<tr><td>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.[11]
b. Loss of all Transmission lines on a common Right-of-Way[11].
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.</td>
<td>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[10] resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.</td></tr>
</table>

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. ~~d.~~h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~e.~~i. 3Ø internal breaker fault. ~~f.~~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: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communication system that is both ~~which is not~~ monitored ~~or not~~ and reported at a Control Center shall not be considered non-redundant); c. A single station dc supply associated with protective functions required for Normal Clearing, ~~and that~~(except a single station dc supply that is ~~not~~ both monitored ~~or not~~and reported at a Control Center for both low voltage and open circuit shall not be considered non-redundant); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant).

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

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

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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 in Protection Systems, as identified in:
  - Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011; and
  - the report dated September 2015 by two subcommittees under NERC Planning Committee , the System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee, titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 (October 17, 2013) approving Reliability Standard TPL-001-4, relating to:
  - modeling known outages with a duration of less than six months (paragraph 40); and
  - adding stability analysis for the outage of major Transmission equipment with a lead time of one year or more (paragraph 89); and;
- To replace references to the Reliability Standards MOD-010 and MOD-012, which have been superseded by MOD-032.

General Considerations

The standard will become effective 36 months following regulatory approval. The 36-month period provides time for Planning Coordinators and Transmission Planners to develop, among other things:

- A procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- Coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional analysis required due to changes in the standard.

Following this 36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5 for Category P5 planning events involving single points of failure in Protection Systems.

Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation plan reflects consideration that Planning Coordinators and Transmission Planners will need time to conduct the new studies and analyses in order to coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5 (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2, Part 2.7 for the non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in those jurisdictions where governmental approval is required.

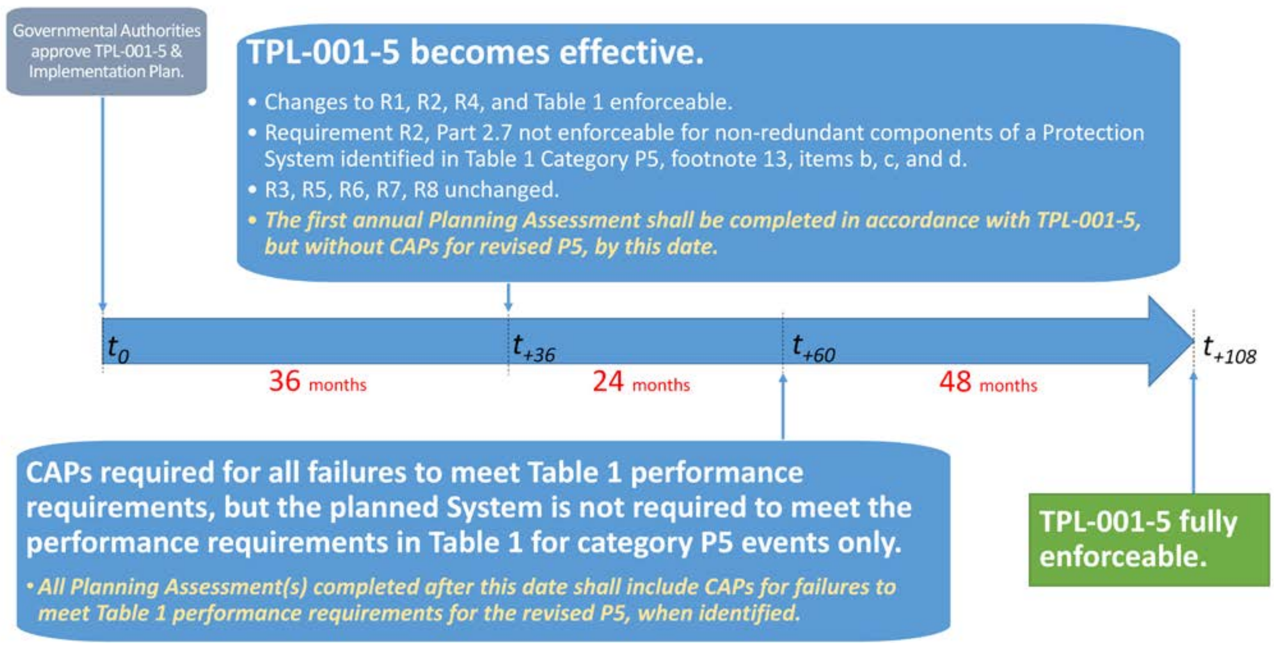

Figure 1 Implementation Plan Timeline

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 a, b, c, and d

Entities 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 a, b, c, and d until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5 with the bolded part of Requirement R2, Part 2.7 that states: "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.**"

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) 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 a, b, c, and d by 24 months after the effective date of the standard.

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.

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~~in Protection Systems, as identified in~~ ~~:
    - Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011~~,~~; and
    - the report dated September 2015 by two subcommittees under NERC Planning Committee , the 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~~) approving Reliability Standard TPL-001-4, relating to:
    - modeling known outages with a duration of less than six months~~;~~ (paragraph 40); and
    - adding stability analysis for the outage of major Transmission ~~E~~equipment with a lead time of one year or more~~.~~ (paragraph 89); and;
- To replace references to the Reliability Standards MOD-010 and MOD-012~~ standards~~, which have been superseded by ~~the ~~MOD-032~~ Reliability Standard~~.

General Considerations

~~This implementation plan provides 36 months until the~~The standard will become effective ~~date of the Standard, providing~~36 months following regulatory approval. The 36-month period provides time for 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 procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- ~~A process for establishing coordination~~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~~.~~ required due to changes in the standard.

~~In addition,~~
Following this ~~implementation plan includes~~36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5 ~~to address newly-added studies~~ for Category P5~~ and P8~~ planning events involving single points of failure ~~on~~in Protection Systems.

~~This extended implementation period for the~~Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**"~~, acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed~~" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation ~~period~~plan reflects consideration that Planning Coordinators and Transmission Planners will need time ~~beyond that provided~~ to conduct the new studies and ~~analysis~~analyses in order to ~~develop processes for coordination~~coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5~~ and P8 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 non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

~~Lastly, the provisions related to CAP 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.~~
Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in those jurisdictions where governmental approval is required.

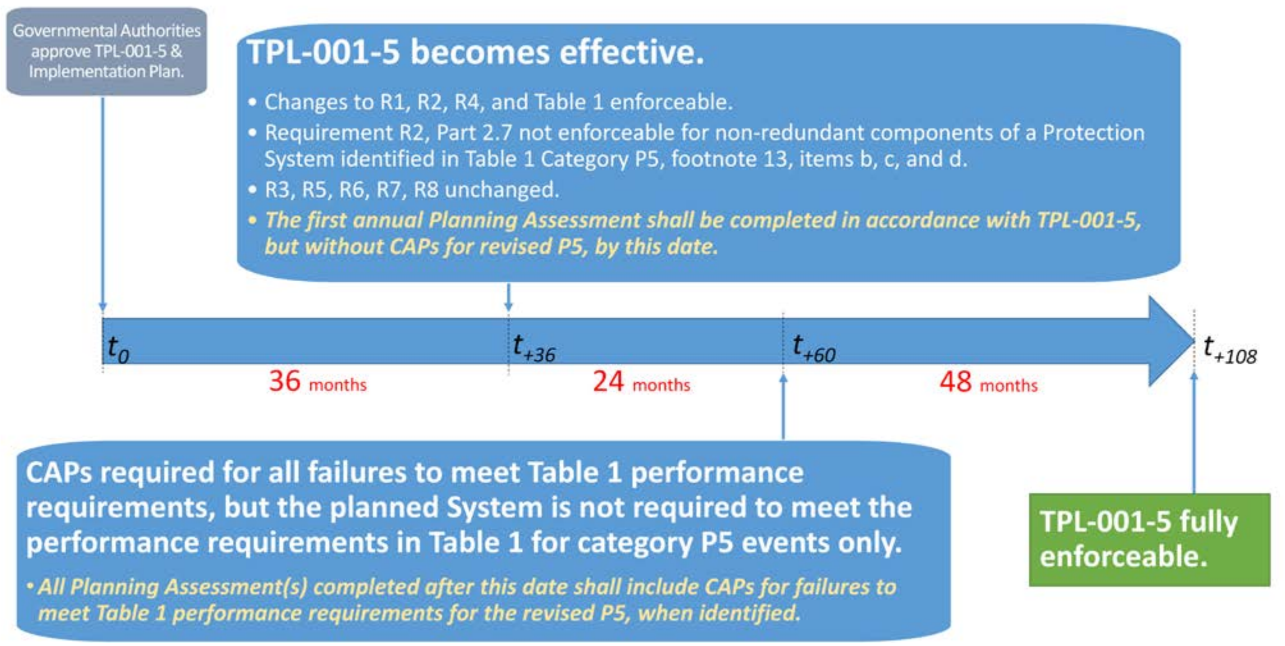

Figure 1 Implementation Plan Timeline

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 a, b, c, and d ~~and P8~~

Entit~~l~~ies 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 a, b, c, and d ~~or P8~~ until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for ~~P5 or P8 events only, Transmission Planners~~the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and ~~Planning Coordinators~~d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5 with the ~~section~~bolded part of Requirement R2, Part 2.7 that states: "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~~", until 96 months after the effective date of Reliability Standard TPL-001-5.~~."

~~**Note Regarding CAPs**~~
~~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, CAP 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 ~~without CAPs for revised P5 or P8~~ in accordance with TPL-001-5 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) 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 a, b, c, and d ~~and P8~~ by 24 months after the effective date of ~~Reliability Standard TPL-001-5~~the standard.

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.

Unofficial Comment Form

Project 2015-10 Single Points of Failure TPL-001

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2015-10 TPL-001-5 – Transmission System Planning Performance Requirements** by **8 p.m. Eastern, Tuesday, September 11, 2018.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Latrice Harkness (via email), or at (404) 446-9728.

Background Information

The SPCS and the SAMS conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action**.**

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with the proposed revisions to TPL-001-4?

   ☐ Yes
   ☐ No

   Comments:

4. Do you agree with the proposed implementation plan?

   ☐ Yes
   ☐ No

   Comments:

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

   ☐ Yes
   ☐ No

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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 instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

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:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

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.

Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **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. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **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-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:	Requirement R1 body has been updated to reference MOD-032 standard number in body of requirement. Requirement R1, Part 1.1.2 and subparts have been deleted. Selection of known outages will be addressed in Requirement R2, Parts 2.1.4 and 2.4.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. **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	**1.1.1.** Existing Facilities. ~~**1.1.2.** Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:~~ ~~**1.1.2.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for~~	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~P1 events in Table 1 when concurrent with the selected known outage(s); and~~ ~~1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.~~ ~~1.1.3.~~1.1.2. New planned Facilities and changes to existing Facilities. ~~1.1.4.~~1.1.3. Real and reactive Load forecasts. ~~1.1.5.~~1.1.4. Known commitments for Firm	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Transmission Service and Interchange. ~~1.1.6.~~1.1.5. Resources (supply or demand side) required for Load.	
TPL-001-4, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	TPL-001-5, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	No modifications made.
TPL-001-4, Requirement R2 R2 Part 2.1.4 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	TPL-001-5, Requirement R2 R2 Part 2.1.3 2.1.43For 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	Requirement R2, Part 2.1.4 moved to Requirement R2, Part 2.1.3

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	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.	
TPL-001-4, Requirement R2 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	TPL-001-5, Requirement R2 ~~2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in~~	Requirement R2 Part 2.1.3 moved to Requirement R2 Part 2.1.4 A properly planned Transmission system should facilitate maintenance outages

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
conditions when known outages are scheduled.	~~Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.~~ 2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning coordinator or Transmission Planners's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has	without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1	
TPL-001-4, Requirement R2 2.4.3. 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.	TPL-001-5, Requirement R2 2.4.43. 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.	Requirement R2, Part 2.4.3 has been moved back to 2.4.3 as it was in TPL-001-4.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	TPL-001-5, Requirement R2 ~~2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.~~3~~4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System	TPL-001-5, Requirement R2, Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.	
	TPL-001-5, Requirement R2 **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.	TPL-001-5, Requirement R2, Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R2 Requirement R2 Part 2.7 **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:	TPL-001-5, Requirement R2 Requirement R2 Part 2.7 **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~~3 and 2.4.3. The Corrective Action Plan(s) shall:	TPL-001-5, Requirement R2, Part 2.4.5 Requirement R2, Part 2.7 Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard.
TPL-001-4, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for	TPL-001-5, Requirement R3 **R3.** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for	Requirement R3, Part 3.2 Document internal conforming clean-up to move the last sentence of

Standard: TPL-001-5		
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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:	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. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the	Requirement R3, Part 3.5 to Requirement R3, Part 3.2.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. **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	

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(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	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
included in the Contingency list. 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.	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.~~	
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.
TPL-001-4, Requirement R4	TPL-001-5, Requirement R4,	<u>TPL-001-5, Requirement R4, Part 4.2</u>

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	**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	Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. 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. **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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.~~	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

NERC

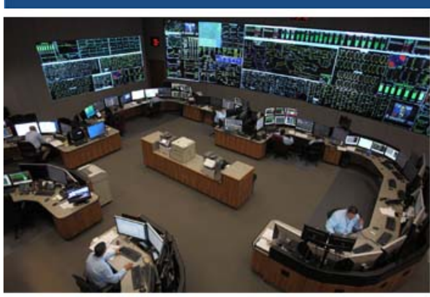
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

July 2018

RELIABILITY | ACCOUNTABILITY

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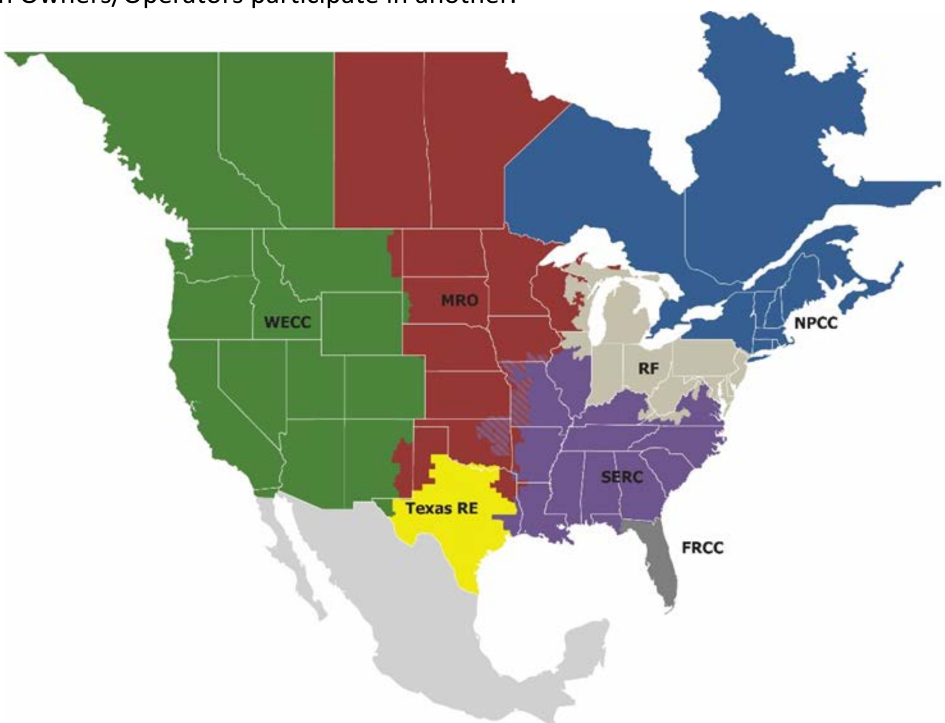
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standard Drafting Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," the Category P5 event incorporates Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 Planning Events and Stability Extreme Events.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, that Category P3 and P6 do not sufficiently cover planned maintenance outages, and the Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration, shift the consideration of known outages from Requirement R1, which requires what System models shall represent, to Requirement R2, Parts 2.1 and 2.4, which require the study and assessment of known outages. Further, proposed revisions include a requirement to document an outage coordination procedure or the technical rationale for the determination of which known outages to study. Proposed revisions also included the addition of stability assessment for long lead equipment that does not have a spare.

Summary of proposed revisions

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Removed this requirement.
- Requirement R2, Part 2.1.4 – Added model conditions for steady state analysis of P0 and P1 events for known outages.
- Requirement R2, Part 2.4.4 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R3, Part 3.2 – Document internal conforming clean-up to incorporate the last sentence of Part 3.5.

- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify the SPF that should be considered.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with SPF in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order No. 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF.

The SDT strongly considered the recommendations of the SPCS and SAMS report, recognizing that the purpose of that report was to determine whether a reliability concern existed demanding NERC to address the study of SPF on Protection Systems. The formation of the Project 2015-10 directly resulted from the SPCS and SAMS report recommendations. However, the SDT's obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments which adequately account for the reliability risk posed by SPF on Protection Systems.

FERC Order No. 786

In FERC Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order No. 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System (BES) were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In FERC Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the technical conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC technical conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC Planning Committee (PC) and Operating Committee (OC), summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action.

[3] *See* *Industry Advisory: Single Point of Failure*
http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf

To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order No. 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SDT strongly considered the recommendations of the SPCS and SAMS report, as specified by the Project 2015-10 Single Points of Failure Standards Authorization Request (SAR). The SDT recognized that its obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments. The SPCS and SAMS report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 SDT are summarized in the following section.

Revisions to TPL-001-4

Single Points of Failure – Category P5 Planning Events

The SPCS and SAMS report states, "Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists)".

The modifications to the Category P5 Planning event description are intended to be aligned with the changes to the Table 1, Footnote 13. The SDT has modified Table 1, Footnote 13 to capture the SAMS/SPCS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified SPF of concern. Footnote 13 describes the non-redundant Protection System components to be considered for Category P5 Planning Events, and is discussed further below.

The Table 1 Category P5 event describes a Contingency where a single line-to-ground (SLG) fault occurs and Delayed Fault Clearing results due to the failure of the Protection System, protecting the Faulted element, to operate as designed. Typically, the two most important aspects of the P5 event that affect simulation are the magnitude of SLG fault current and the mode of Protection System failure leading to Delayed Clearing. The latter is especially important and the mode of Protection System failure details make the P5 event unique. The Transmission Planner or Planning Coordinator must be cognizant of the time period during which the Protection System removes Elements from service, as well as the sequence of their removal during isolation of the fault. By definition, Normal Clearing is not expected when a non-redundant component of a Protection System is simulated to have failed; the P5 event implies that the Protection System does not operate as designed to clear the SLG fault in the time normally expected with proper functioning of the installed Protection System. Therefore, when a non-redundant component of a Protection System fails, Delayed Clearing results. This means that correct operation of the backup Protection System occurs with the intentionally designed time delay before fault clearing. Additionally, there may be significant differences in final System configuration due to the Protection System operation to clear the faulted Element. For example, more System Elements may be removed from service when the backup Protection System operates, consistent with Delayed Clearing, than may be expected during primary Protection System operation expected for Normal Clearing. The expected time delays for Protection System operation are critical for proper simulation of the P5 event.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 Planning Events will likely be to add Protection System component redundancy, consistent with the components to be considered in Footnote 13. Protection System redundancy changes to address Category P5 Event concerns should also reduce or even negate non-redundant components that need to be considered in assessing System performance resulting from simulation of the 2e-2h Extreme Events; hence, potentially mitigating many concerns.

Clarification: Why address SPF in TPL-001 and not create a new Reliability Standard for this purpose?

As part of the recommendations from the SPCS and SAMS report, the option to create a new Reliability Standard to address SPF in the Protection System was considered. Both a new TPL standard for planning-related studies and assessment, as well as a new Protection and Control standard to specify Protection System redundancy were debated by SPCS and SAMS. Ultimately, the recommendation of the SPCS and SAMS report, leading to the formation of the Project 2015-10 SDT, focused upon the simulation and study assessment of the Transmission system given non-redundant components of the Protection System instead of mandating a level of redundancy across a diverse set of equipment and utilities in North America.

It is important to emphasize that modifications to the TPL-001-5 Table 1 Category P5 Planning Event, the TPL-001-5 Table 1 Extreme Stability Events, and related changes to Table 1, Footnote 13 do not establish or mandate a level of redundancy for Protection Systems. Quite the contrary: the modifications presented in TPL-001-5 require planning entities to consider the non-redundant components of Protection Systems that may exist within their respective Systems, to execute appropriate studies, and to assess the impacts that these SPF may have upon the ability to meet Table 1 System performance requirements given Delayed Clearing. TPL-001-5 does not mandate redundancy; TPL-001-5 requires that some non-redundancy components of a Protection System be considered during annual Planning Assessments.

Clarification: What is the difference between a top-down versus bottom-up approach to Category P5 Events?

As part of simulating and analyzing results of P5 Event assessments, two common approaches to the Stability portion of simulations may be appropriate for planning entities to undertake. The first, referred to as the top-down approach, may initially focus upon determining critical clearing times for an entity's System topology given SLG faults. Once critical clearing times are obtained, the planning entity has the opportunity to collaborate with System Protection personnel to assess whether the installed Protection System may achieve the required performance. An advantage of the top-down approach is that the analytical burden to determine critical clearing times is front-loaded upon the planning entity and specific details regarding the Protection System are unnecessary prior to executing dynamics simulations. Conversely, the bottom-up approach may commence by the planning entity requesting the detailed causality and clearing times for SPF on the Protection System from Protection System personnel, requiring an extensive review of installed Protection Systems at the outset. While this approach may delay the execution of P5 Event studies, it may eliminate System topology that is not susceptible to SPF on the Protection System based upon Protection System personnel input and reduces the planning entity's dynamics simulation burden. Whether utilizing a top-down, bottom-up, combination of the two, or any other appropriate approach, the obligation specified in Table 1, Footnote 13 is for the planning entity to consider the non-redundant components of a Protection System that may lead to Delayed Clearing when simulating the P5 Event.

Clarification: Is backup protection redundant?

The majority of BES Protection Systems are designed with overlapping zonal protection, including backup systems which eventually clear a fault in the event of a failure of the Protection System which is designed for Normal Clearing. Backup Protection Systems are not redundant for purposes of TPL-001-5 Table 1, Category P5 Events because they result in Delayed Clearing and/or trip more Elements than the primary Protection System designed for Normal Clearing. Where the Protection System is designed with backup protections, the backup protection clearing time for a SLG fault must be the same as the clearing time for the primary Protection System designed for Normal Clearing, and must trip identical Elements, in order for the backup Protection System to be considered redundant to the primary Protection System. The SDT expects this type of design to be rare in its implementation, and correspondingly, backup protection is not considered redundant.

Table 1, Footnote 13

Footnote 13 is included in the TPL-001-5 Reliability Standard for the purpose of focusing the Transmission Planner and Planning Coordinator consideration of non-redundant components of a Protection System that may, when they fail, lead to Delayed Clearing of the SLG fault simulated as part of the P5 event.

The SPCS and SAMS report recommended replacing “relay” with “component of a Protection System” in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of ’Protection System‘ for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A factor that the SDT considered when seeking to translate the SPCS and SAMS recommendations into the proposed TPL-001-5 Table 1, Footnote 13 was the need for Planning Coordinators and Transmission Planners to collaborate with System Protection personnel. The SDT recognized that the planning entities do not always have enough information alone to consider Protection System modes of failure or Delayed Clearing than may result. Likewise, the SPCS and SAMS recommendations were adapted to target the potential non-redundant components of a Protection System that may likely need System Protection personnel input when determining how study simulations, performed by the planning entity, should be executed. Based on discussion and industry comment, the SDT revised Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS and SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Clarification: Why is monitored and reported to a Control Center used in parts of Footnote 13?

The SDT recognized that some components of a Protection System may be monitored and their integrity reported to a Control Center. Different than an indication of a component failure that may be displayed in a remote site or in a location that may go unnoticed for a period, reporting to a Control Center implies that an unsatisfactory condition would be identified and corrective action be directed in short order. Given that a risk-based approach to non-redundant components of a Protection System is appropriate, the SDT believed that components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.

Clarification: Why are relays that respond to electrical quantities addressed?

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the SDT sought to limit the scope of Footnote 13a with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. A SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the SDT did not include backup protective relays in the scope of Footnote 13a given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The SDT recognized that BES Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event (See Figure 1 and 2).

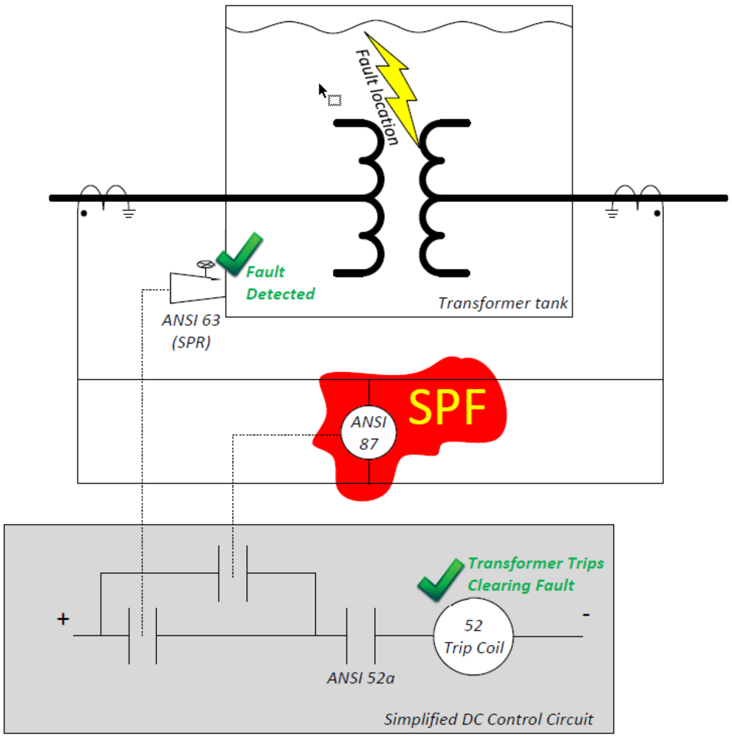


Figure 1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

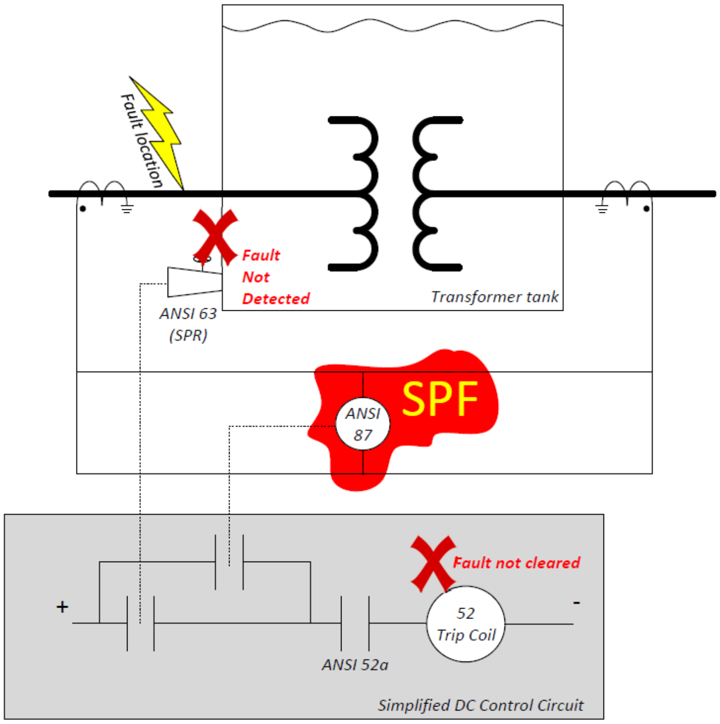


Figure 2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Clarification: What is comparable and what is not comparable for purposes of footnote 13?

The use of "comparable" in Table 1, Footnote 13a applies only to alternatives for a single protective relay that responds to electrical quantities. For an alternative to be comparable to a single protective relay that responds to electrical quantities, the alternative must operate as designed to clear the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly. Clearly, any alternative to a single protective relay that responds to electrical quantities may result in a different Element tripping sequence, leading to a different System topology after fault clearing which must be considered. Therefore, a comparable alternative to a single protective relay that responds to electrical quantities must result in fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements.

Clarification: Why are communication-aided Protection Systems addressed?

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The SDT augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The SDT concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the BES can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Clarification: Why are DC supplies addressed?

The SDT adopted the fundamental principles of the SAMS/SPCS recommendations regarding station Protection System DC supply. Failure of a single station Protection System DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The SDT partly modified the SAMS/SPCS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit Therefore, this requirement may be more applicable to legacy systems.

Clarification: What differentiates a single station DC supply (Footnote 13c) from a single control circuitry (Footnote 13d)?

The station DC supply includes station battery, battery chargers and non-battery-based dc supply, as enumerated in the NERC Glossary of Terms definition of Protection System. The control circuitry includes everything from where the station DC supply terminates through and including the trip coils, including the wiring, as well as auxiliary and lockout relays. Further, the NERC Technical Paper *"Protection System Reliability Redundancy of Protection System Elements"* (November 2008) shows a demarcation between DC supply and the remainder of DC control circuitry. The SAMS and SPCS report and recommendations align with Figure 5-12 from this technical paper, shown below as Figure 3.

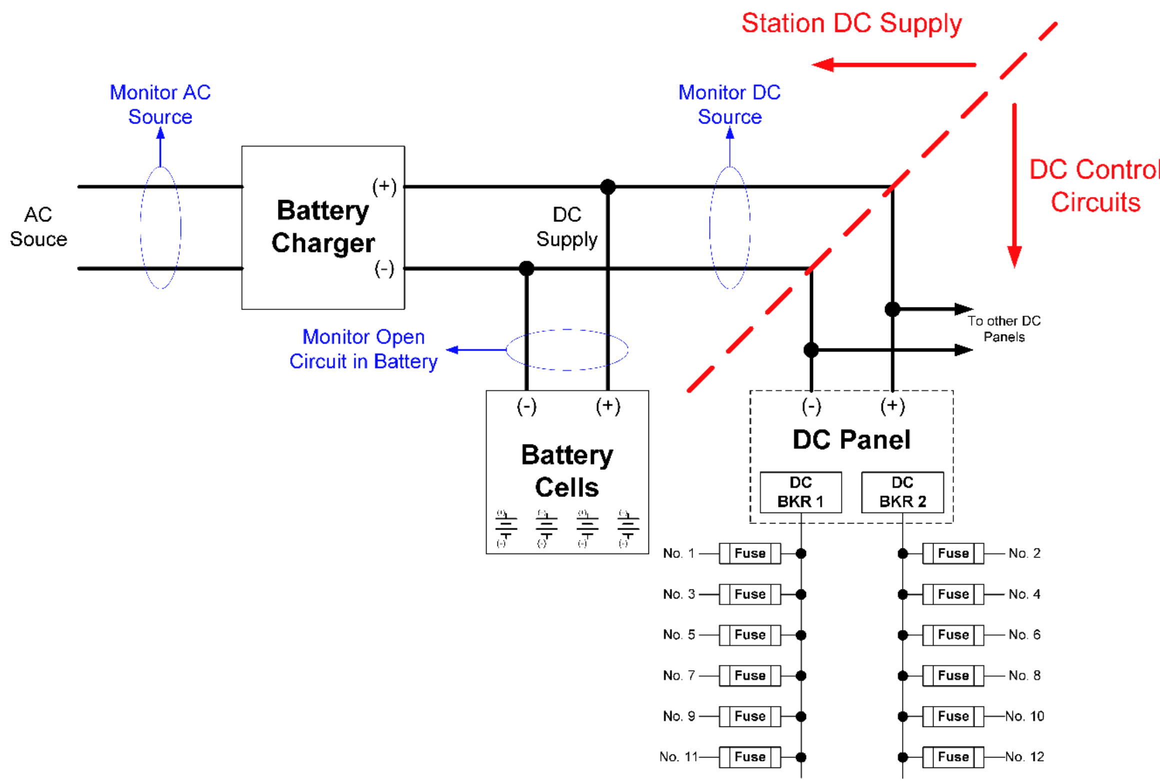


Figure 3 – Station DC supply and monitoring (Figure 5-2, from NERC Technical Paper "Protection System Reliability Redundancy of Protection System Elements", Nov 2008)

Simply monitoring for low voltage on the DC supply may omit situations where the DC supply voltage is satisfactory but the source path to DC control circuits may be open circuited. Thus, monitoring for low voltage and open circuit of the DC supply should be considered. Additionally, while the wiring in both the DC supply and the DC circuit have lower probabilities of failure as compared to other Protection System components, the SPCS and SAMS report identified this as a SPF risk.

Clarification: Is a battery charging system appropriate redundancy for the battery?
Battery chargers may not be of sufficient power to source current necessary to operate one or more breakers. For example, it is unlikely that a battery charger without a station battery in parallel would be capable of opening several breakers when demanded by a bus differential Protection System operation. Therefore, a battery charger cannot take the place of a redundant battery DC supply.

The Distinction between Category P4 and Category P5 Planning Events
"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 Planning Events. The sequence and timing of Protection System action leading to Delayed Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed

Clearing associated with circuit breaker failure. Likewise, the Delayed Clearing time that results from a Category P5 Event may be significantly longer that that expected when simulating Category P4 Event.

It is noted that there may be many instances where a fault followed by a breaker failure results in the exact same study simulations as a fault followed by a failure of a non-redundant component of a Protection System. There could be slight differences in clearing times and the Planning Coordinator or Transmission Planner may choose to simulate a P4 and P5 as one study using the longest expected clearing time. However**,** in the event of a bus fault followed by a bus differential protection failure, there may be a single relay (ANSI device 86) communicating to several breakers attached to the faulted bus. A bus fault on a breaker and a half configuration or double breaker double bus configuration may be particularly problematic in this case. For the Category P5 Event simulating this type of Protection System failure, none of the breakers which should open to clear the fault will receive the appropriate signal from the failed SPF relay and will not clear the bus fault. This makes the bus differential P5 Event significantly more severe than the P4 Event. The FERC Order 754 Section 1600 Data Request was specific to bus faults followed by a SPF of the Protection System.

In some cases, a P4 Event simulation at a specific location will be the same as the P5 Event simulation. For example: the failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open to clear a fault. Therefore, the P4 Event and the P5 Event may simulate the identical causality. However, if this simulation results in a performance requirement violation, the CAP must include mitigations for the P4 Event as well the P5 Event.

Extreme Events 2e-2h listed from the stability column of Table 1

Analysis of the data collected under the FERC Order No. 754 Section 1600 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further consideration. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis should be placed on assessment of three-phase faults involving a SPF on the Protection System. This concern, made manifest through the study of a three-phase fault and a SPF on a Protection System, is appropriately addressed as an extreme event in TPL-001-5, Requirement R4, Part 4.2. While less probable than SLG faults, three-phase faults frequently initiate as single-phase-to-ground with Delayed Clearing and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1, Category P5 Event. TPL-001-5, Requirement R4, Part 4.2, specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of extreme events. Thus, the SDT has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but encourages consideration of implementing mitigating actions if it is cost-effective to do so.

Requirement R3, Parts 3.2 and 3.5 and Requirement R4, Parts 4.2 and 4.5

The SDT proposes non-substantive editorial changes to combine part of Requirement R3, Part 3.5 with Requirement R3, Part 3.2. The rearrangement of Requirement 3, Parts 3.2 and 3.5 were done to improve consistency within the Standard and do not create any new requirements. This is also true for Requirement R4, Part 4.2 and 4.5. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable low-cost, cost-effective measures to lessen the risk or severity of these events.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

FERC Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not “hypothetical outages” and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing “with duration of at least six months” and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order No. 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an “academic exercise” due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order No. 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

Revisions to TPL-001-4

Requirement R2, Parts 2.1.4 and 2.4.4

The SDT gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying, and sometimes conflicting, perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the Transmission Planner or Planning Coordinator.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective continent wide means of addressing the FERC directive. However, FERC Order No. 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available. The proposed modification is for consideration of known outages beyond, and therefore outside of, the Operations Planning time horizon.

The most prominent change the SDT proposes to address the FERC directive was to migrate the assessment of known outages from Requirement R1, which requires that System models shall represent, to Requirement R2, Parts 2.1 and 2.4 which requires how analyses shall be assessed and supported by studies. The SDT believed that this proposed change to where the assessment of known outages is specified in the TPL-001-5 requirements better aligns the approach necessary for the planning entities to execute their annual Planning Assessments.

The SDT modified Requirement R2, Part 2.1.4 and 2.4.4 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that Planning Coordinators and Transmission Planners currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be considered. The Planning Coordinator and Transmission Planner must have either a documented outage coordination procedure or technical rationale to select which known outages shall be assessed. The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination. Consistent with the intention of Order No. 786, the SDT included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be assessed. It is only necessary to consider known outages expected to cause more severe System impacts, such as those that may result in Non-Consequential Load Loss for P1 event in Table 1. This allows the Planning Coordinator and Transmission Planner to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary assessment of outages which the Planning Coordinator and Transmission Planner do not expect to be problematic. The System conditions, such as peak or Off-Peak, that are expected during the period when the known outage is planned further limits the "non-hypothetical" analyses that may be performed. While it is inappropriate to assume that all known outages simulated in conjunction with Category P0 or P1 Events are identical to Category P3 or P6 Events, past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1 . However, it is imperative for the Planning Coordinator or Transmission Planner to document the justification for

supporting the known outage exclusion based upon past or current studies and why the post-Contingency System conditions and configuration are comparable in their technical rationale.

Clarification: Does TPL-001-5 duplicate requirements of IRO-017-1 for outage coordination?

The SDT was concerned that in order for the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, it must first assess the known outages as part of that Planning Assessment. However, if the Planning Coordinator or Transmission Planner does not know what outages to study, clearly outages may be omitted from having the opportunity for jointly developed solutions with the Reliability Coordinator, required in IRO-017-1. The SDT believed that the feedback loop between the planning entities and the Reliability Coordinator ends with the planning entities presenting their study results in the Planning Assessment, but must begin with strong collaboration and sourcing of information regarding known outages that should be studied beyond the Operations Horizon by the Reliability Coordinator. Therefore, the SDT does not believe that there is duplication between the proposed TPL-001-5 and IRO-017-1 standards. Moreover, the SDT believes there is an implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon.

FERC Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.

- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2, Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 SDT revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning entities and System Protection personnel that will need to collaborate when conducting the studies and submitting the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines. Coordination with Generator Owners, Transmission Owners, and Distribution Providers will be necessary to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant component of a Protection System could result in a potential reliability risk. Transmission Planners and Planning Coordinators must obtain this information, as well as resulting fault clearing times, to perform proper studies.

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Standard Drafting Team (SDT) Proposal for Known Outages

The SDT did not feel like a time duration alone would capture “significant outages.” Additionally, the language allows TP’s and PC’s to develop a process for selecting “significant outages” to be studied in the Near-Term Transmission Planning Horizon utilizing their knowledge or other study results to aid in determination of significant outages. The team removed Requirement R1, Part 1.1.2. The team has modified Requirement R2, Parts 2.1.4 and 2.4.4 as show below. Please not that Requirement R2, Parts 2.1.4 and 2.4.4 were respectively, 2.1.3 and 2.1.4. The SDT has re-organized the Requirements to provide a better flow.

Proposed Revisions (Draft 4):

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-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) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:~~

~~**1.1.1.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s); and~~

~~**1.1.1.2.** Does not exclude known outage(s) solely based upon the outage duration.~~

~~1.1.3.~~1.1.2. New planned Facilities and changes to existing Facilities.

~~1.1.4.~~1.1.3. Real and reactive Load forecasts.

~~1.1.5.~~1.1.4. Known commitments for Firm Transmission Service and Interchange.

~~1.1.6.~~1.1.5. Resources (supply or demand side) required for Load.

Requirement R2, Parts 2.1.4 and 2.4.4 (Draft 4)

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning coordinator or Transmission Planners's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

Single Point of Failure of the Protection System (Footnote 13)

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling Subcommittee (SAMS) report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:

- Remove the phrase "or a relay failure13" from items a, b, c, and d to create distinct events only for stuck breakers.
- Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure13" with "a component failure of a Protection System13."

- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."[1]
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection System13 that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Revisions by the SDT to Satisfy FERC Order

The recommendations from the SPCS and SAMS report were so specific, there were no other options considered. The SDT has made revisions for further clarification based on team discussion and industry comment.

Proposed Revision (Draft 4)

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

   a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;

   b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communication system that is both ~~which is not~~ monitored ~~or not~~ and reported at a Control Center shall not be considered non-redundant);

   c. A single station dc supply associated with protective functions required for Normal Clearing, ~~and that~~(except a single station dc supply that is ~~not~~ both monitored ~~or not~~and reported at a Control Center for both low voltage and open circuit shall not be considered non-redundant);

   d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant).

SDT Proposal for Table 1 Footnote 13:

The SDT added clarifications to the previous draft option which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

Extreme Events:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754, Section 1600 data collection and report indicated a risk to the BES for three phase faults followed by single points of failure of a protection system. The standard drafting team feels that there is a reliability risk to the BES if Cascading or instability results in a three-phase fault followed by single point of failure of a protection system. The SDT decided to make this an Extreme Event if a three-phase fault following by a single points of failure resulted in Cascading or instability following industry comments.

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Standards Announcement

Reminder

Project 2015-10 Single Points of Failure

Additional Ballots and Non-binding Poll Open through September 14, 2018

Now Available

The additional ballots for **TPL-001-5 – Transmission System Planning Performance Requirements** and implementation plan, and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Friday, September 14, 2018.**

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience issues using the SBS, contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

UPDATED Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Extended: Open through September 14, 2018

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Friday, September 14, 2018.**

The Implementation Plan has been updated to reflect a revised compliance date. The comment period has been extended to provide stakeholders adequate time to review the updated documents and provide meaningful feedback.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **September 5-14, 2018**.

For information on the Standards Development Process, refer to the Standard Processes Manual**.**

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/144)
Ballot Name: 2015-10 Single Points of Failure TPL-001-5 AB 3 ST
Voting Start Date: 9/5/2018 12:01:00 AM
Voting End Date: 9/14/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 223
Total Ballot Pool: 294
Quorum: 75.85
Weighted Segment Value: 69.07

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	32	0.604	21	0.396	1	3	22
Segment: 2	8	0.8	5	0.5	3	0.3	0	0	0
Segment: 3	67	1	36	0.655	19	0.345	0	1	11
Segment: 4	16	1	8	0.8	2	0.2	0	0	6
Segment: 5	65	1	28	0.683	13	0.317	0	4	20
Segment: 6	49	1	21	0.618	13	0.382	0	4	11
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.6	5	0.5	1	0.1	0	0	0
Totals:	294	6.6	137	4.559	72	2.041	1	13	71

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	Comments Submitted
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	No Comment Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	Comments Submitted
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	Comments Submitted
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	JEA	Garry Baker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Negative	Comments Submitted
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Negative	Comments Submitted
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		None	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/144)
Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Implementation Plan AB 2 ST
Voting Start Date: 9/5/2018 12:01:00 AM
Voting End Date: 9/14/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 222
Total Ballot Pool: 294
Quorum: 75.51
Weighted Segment Value: 73.27

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	35	0.686	16	0.314	1	4	23
Segment: 2	8	0.6	3	0.3	3	0.3	0	2	0
Segment: 3	67	1	40	0.741	14	0.259	0	2	11
Segment: 4	16	1	8	0.8	2	0.2	0	0	6
Segment: 5	65	1	31	0.775	9	0.225	0	4	21
Segment: 6	49	1	25	0.714	10	0.286	0	4	10
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.5	4	0.4	1	0.1	0	1	0
Totals:	294	6.3	148	4.616	55	1.684	1	18	72

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	American Transmission Company, LLC	Douglas Johnson		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Third-Party Comments
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		None	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	Comments Submitted
1	Muscatine Power and Water	Andy Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		None	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Third-Party Comments
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	No Comment Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Negative	Third-Party Comments
1	Xcel Energy, Inc.	Dean Schiro		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	Comments Submitted
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Negative	Third-Party Comments
3	AEP	Leanna Lamatrice		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Third-Party Comments
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	Third-Party Comments
3	JEA	Garry Baker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Third-Party Comments
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		None	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	Comments Submitted
5	Los Angeles Department of Water and Power	Glenn Barry		Negative	Comments Submitted
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		None	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	Third-Party Comments
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		None	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Negative	Comments Submitted
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	Comments Submitted
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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BALLOT RESULTS

Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Non-binding Poll AB 3 NB
Voting Start Date: 9/5/2018 12:01:00 AM
Voting End Date: 9/17/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 215
Total Ballot Pool: 274
Quorum: 78.47
Weighted Segment Value: 68.64

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	71	1	28	0.636	16	0.364	11	16
Segment: 2	7	0.4	4	0.4	0	0	3	0
Segment: 3	63	1	28	0.651	15	0.349	10	10
Segment: 4	15	0.9	8	0.8	1	0.1	0	6
Segment: 5	61	1	25	0.735	9	0.265	10	17
Segment: 6	47	1	17	0.586	12	0.414	9	9
Segment: 7	1	0	0	0	0	0	1	0
Segment: 8	2	0.1	1	0.1	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0
Segment: 10	6	0.4	4	0.4	0	0	2	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Totals:	274	5.9	116	4.409	53	1.491	46	59

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Central Electric Power Cooperative (Missouri)	Michael Bax		None	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	Comments Submitted
1	Cleco Corporation	John Lindsey	Louis Guidry	Negative	Comments Submitted
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Corn Belt Power Cooperative	larry brusseau		None	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Laura Lee		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		None	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	Comments Submitted
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Affirmative	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		None	N/A
1	LS Power Transmission, LLC	John Seelke		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	Comments Submitted
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	Comments Submitted
1	Western Area Power Administration	sean erickson		Negative	Comments Submitted
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	Comments Submitted
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	Comments Submitted
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Cowlitz County PUD	Russell Noble		None	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	Duke Energy	Lee Schuster		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	Comments Submitted
3	Great River Energy	Brian Glover		Negative	Comments Submitted
3	JEA	Garry Baker		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		None	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	Comments Submitted
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	Comments Submitted
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Anthony Jankowski		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	Negative	Comments Submitted
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Abstain	N/A
5	FirstEnergy - FirstEnergy Solutions	Robert Loy		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	Comments Submitted
5	Great River Energy	Preston Walsh		None	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lakeland Electric	Jim Howard		None	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		None	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		None	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		None	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	Comments Submitted
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Negative	Comments Submitted
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	Comments Submitted
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Brenda Hampton		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Manitoba Hydro	Blair Mukanik		Negative	Comments Submitted
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		None	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	Comments Submitted
6	Portland General Electric Co.	Daniel Mason		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	Comments Submitted
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Abstain	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Showing 1 to 274 of 274 entries

Standards Announcement

Project 2015-10 Single Points of Failure

Formal Comment Period Open through September 11, 2018

Now Available

A 45-day formal comment period for **TPL-001-5 – Transmission System Planning Performance Requirements** is open through **8 p.m. Eastern, Tuesday, September 11, 2018.**

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Wendy Muller. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 31 – September 11, 2018**.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5 Draft 4
Comment Period Start Date:	7/30/2018
Comment Period End Date:	9/14/2018
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 AB 3 ST 2015-10 Single Points of Failure TPL-001-5 Implementation Plan AB 2 ST

There were 51 sets of responses, including comments from approximately 148 different people from approximately 96 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

3. Do you agree with the proposed revisions to TPL-001-4?

4. Do you agree with the proposed implementation plan?

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Standards Review Committee	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
					Helen Lainis	IESO	2	NPCC
					Michael Puscas	ISO New England, Inc.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC

					Marjorie Parsons	Tennessee Valley Authority	6	SERC
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
	Kayleigh Wilkerson	5			Kayleigh Wilkerson	Lincoln Electric System	5	MRO

Lincoln Electric System				Lincoln Electric System	Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC

					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter state	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC

					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mike Kidwell	Empire District Electric Company	1,3,5	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					John Rhea	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP remains concerned by the increased complexity of P5 due the expansion of footnote 13. As written, this footnote requires one to consider a variety of scenarios, including backup zone 2 clearing of a transmission line for pilot relay or pilot communication failure, a breaker failure scenario initiated by trip coil failure (often the same as P4), or remote clearing of a station such as would occur upon a non-redundant bus differential failure.

In order to avoid having to evaluate zone of protection clearing times for every conceivable protection outage condition and document the "consideration" of each of the sub-items under footnote 13, AEP suggests a more generalized P5 event description by adding the text "or Remote (Delayed) Fault Clearing." As a result, it would then read: "Delayed Fault Clearing ***or Remote (Delayed) Fault Clearing*** due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator, 2. Transmission Circuit, etc."

This would continue to make use of the existing glossary term…

Delayed Fault Clearing – Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.

This existing term covers zone 2 backup clearing of transmission lines as well as being duplicative of P4 CB failure scenarios. As a result, a new definition is necessary to cover a gap:
Remote (Delayed) Fault Clearing – Fault clearing necessary to be accomplished at stations one removed from a faulted station bus or other faulted station equipment as a consequence of a protection system single point of failure at the faulted station.

This new term is necessary because relays may not be set with an intentional time delay for clearing remote station faults, and remote clearing may be necessary for non-redundant bus differential schemes. Whether "Delayed" is included in this new term may be immaterial since, while clearing times may be long, there may be no intentional delay, just inherent delay. Footnote 13 could then removed from the draft standard, and instead, be added to the technical supplement to the standard. The would explain the possible causes of delayed clearing or remote delayed clearing, instead of rigorously having to be part of the standard and introducing what we would regard as unnecessary compliance burdens.

Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Footnote 13 is unnecessary. The available powerflow software doesn't simulate protection system equipement (relays, communication systems, dc supplies or control circuitry). The software simulates the transmission network. A protection system failure is simulated by making assumptions about the system's response to the failure and then simulating it. Adding specific equipment to the standard does change the simulation. Without actual protection equipment in the model, it falls on the engineer to make the correct assumptions when doing the simulations. As it should be.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
The phrase "comparable Normal Clearing times" is not consistent with the existing definition of "Normal Clearing" found within the Glossary of Terms Used in NERC Reliability Standards. Additionally, "comparable Normal Clearing times" is not sufficiently clear to allow consistent interpretation for purposes of enforcing the standard.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Footnote 13 does not include all of the applicable single points of failure addressed by 754, such as instrument transformers, and in some cases, includes aspects that do not represent single points of failures, such as redundant breaker trip coils. With regard to breaker trip coils, the lack of two trip coils in a circuit breaker increases the potential for a breaker failure issue (P4), but does not create a relay failure issue since the absence of redundant trip coils would not prevent initiation of breaker failure for failure of a single trip coil.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA agrees with the contents of Footnote 13a, b, and c. However, TVA believes Footnote 13d represents a significant cost impact for a very small probability event. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We suggest to clarify the wording for b), c) and d). The word “except” in parenthesis is awkward. This word perhaps could be replaced with “An exception is”…..	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	

Footnote 13a:

The word “comparable” in footnote 13a requires additional clarification. The Technical Rationale contains conflicting explanations of what is meant by “comparable Normal Clearing times”. In the “Clarification: Is backup protection redundant?” section it appears that a secondary relay would not be considered redundant as the clearing times are not exactly the same as the primary relay. However, in the section titled “Clarification: What is comparable and what is not comparable for purposes of footnote 13?” it appears that slightly slower secondary relaying would be considered redundant if its results in “fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements”. LES recommends modifying the Technical Rationale to clarify the drafting team's intent or else consider modifying footnote 13a to instead state “...that provides comparable Normal Clearing times **(e.g. piloted primary relay and non-piloted secondary relay with different Normal Clearing times)”** to ensure comparable isn't mistaken to mean having identical Clearing times.

Footnote 13c:

Is it the Standard Drafting Team’s intent to consider all substations that don’t have either open circuit monitoring on a single battery bank or two battery banks as non-redundant? LES feels the lack of open circuit monitoring as described in footnote 13c is too restrictive to consider a single station DC supply as non-redundant. Although the Technical Rationale section titled “Clarification: Is a battery charging system appropriate redundancy for the battery?” indicates a battery charger “may not be of sufficient power to source current necessary to operate one or more breakers”, LES feels the individual utility should be permitted to analyze each substation configuration to determine if an open circuit does in fact constitute a non-redundant DC supply.

Additionally, is it the Standard Drafting Team’s intent that non-redundant DC supply be modeled as an entire substation outage? This seems to be the case based on the statement “prevent the operation of all local protection” within the section titled “Clarification: Why are DC supplies addressed?”. However, this is not realistic during an open circuit or low voltage situation as the relays would still be operational and only the backup protection for one line or bus section would operate during a transmission line fault. Additionally, the open circuit monitoring requirement seems unnecessary as PRC-005 provides adequate testing for open circuits. Based on this, LES recommends “open circuit” be excluded from the footnote or else additional detail added to allow for analysis of substation configuration and DC supply capability during an open circuit condition.

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

Comments: Please consider the following:

Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, “shall be considered redundant”.

Add wording like, “Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance.” at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the “Clarification: Is backup clearing redundant?” section on page 3 of the Technical Rationale with a different question and discussion like the following:

Clarification: “When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?”

If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one of these protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- “Voltage and current sensing devices of a Protection System are not considered.” Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- “Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant”. Discussion of this matter is only in the Technical Rationale (p. 5) right now
- “The reclosing relays of a Protection System are not considered.” This matter is not presently discussed in the Technical Rationale.
- “Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant.” This matter is not presently discussed in the Technical Rationale.
- “Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant.” This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
The Technical Rationale does not clarify whether two communication systems must use to separate communication paths (e.g. not the same power line carrier line, single OPGW, microwave tower, tone path, etc.) to qualify as non-redundant systems. The Technical Rationale does not clarify whether control circuitry must use separate paths (e.g. not the same control panel, wire tray, etc.) to qualify as non-redundant circuitry.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy requests further clarification on the use of the term “monitoring” in Footnote 13 item b. Is it the drafting team’s intent, that “monitoring” should be continuous in nature, or would a once a day “check back” of the protection system meet the drafting team’s intent for monitoring? More clarification is needed on this point.

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk.

To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase “shall not be considered non-redundent” to “shall be considered redundant” at the end of the sentence for 13b, 13c, and 13d.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	

Please refer to comments from the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
MidAmerican Energy Company supports comments submitted by the MRO NERC Standards Reveiw Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
The term “comparable Normal Clearing times” as stated in 13.a. may cause inconsistent interpretation between entities and auditors as to what is considered comparable. Consider replacing “…without an alternative that provides comparable Normal Clearing times” with wording used in the Technical Rationale such as “…without an alternative that clears the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly.”	

Consider replacing the double negative wording in 13.b, 13.c and 13.d (“shall not be considered non-redundant”) with “shall be considered redundant.”

Likes 0	
Dislikes 0	

Response
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO

Answer	No
Document Name	

Comment
We suggest that the term “shall not be considered non-redundant” be removed in subsections b), c), and d). Also, we suggest changing the term “except” to “unless” for the three sections. In d), regarding control circuitry, we suggest the following language change: *(unless a single trip coil that is both monitored and reported at a Control Center if it is the only single point of failure in the control circuitry).*

Likes 0	
Dislikes 0	

Response
Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment
We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk. To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase “shall not be considered non-redundent” to “shall be considered redundant” at the end of the sentence for 13b, 13c, and 13d.

Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
We agree with the rational and contents of footnote 13 except for the exception for non-redundant communication equipment that is monitored and alarmed in 13b. Our concern with this exception is that teleprotection equipment that is part of a communication system may be in a failed state and not always generate an alarm.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) recommends the Standards Drafting Team (SDT) provide clarity on the statement "for Normal Clearing". NERC defines "Normal Clearing" as a situation where "[a] protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems." If a communications system associated with protective functions is installed to provide faster tripping than required, does this fall into the "Normal Clearing" definition? If so, the installed communications system associated with protective functions to clear faults faster than necessary is a single point of failure. The SSRG recommends the SDT consider adding language to the technical rationale document that explains the inclusion of the communication system associated with protective functions as a single point of failure.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and	

Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

No.

Westar Energy and Kansas City Power & Light Co. suggest that in Footnote 13d, single lockout relays that are monitored and report to a Control Center should be afforded the same exception as single trip coils that are monitored and reported to a Control Center.

Without the exception, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability.

The companies offer the following revision:

d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except **when either** a single trip coil **or a single lock out relay** is both monitored and reported at a Control Center shall not be considered non-redundant)

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

American Transmission Company (ATC) has concerns about the application and consistency of terms used in Footnote 13 compared to those used in other standards and the NERC Glossary of Terms, specifically Delayed Clearing and Normal Clearing Times. Reliability Standard PRC-004 introduced the term "Composite Protection System," whose definition is based on the principle that an Element’s multiple layers of protection are intended to function collectively. A failure of a Protection System component is not a Misoperation if the performance of the Composite Protection System is correct. A slower than typical operation of a Composite Protection System is considered a Misoperation if the delay results in the operation of at least one other Element’s Composite Protection System. Normal Clearing Time of a Composite Protection System in the context of this standard could be interpreted as the clearing time of the slower of the redundant systems, as long as this clearing time does not result in the operation of another Element’s Composite Protection Systems and acceptable system performance for the scenarios outlined in Footnote 13. However, such guidance or interpretation is currently missing from the Standard or Technical Basis.

In addition, ATC has concerns regarding the application of Footnote 13. Specifically, although monitoring of communication equipment has the potential to reduce the exposure to risk of delayed tripping, it does not eliminate the risk. By not requiring the analysis of delayed clearing on lines lacking redundant communication in the Planning Horizon, ATC (and other companies) may not identify transmission lines that need redundant communication to maintain generator or system stability. During a communication failure event, real-time operations is required to study the impact of delayed clearing for SLG or three- phase faults and mitigate any issues. This particular real-time requirement is maintained in the recent draft standards under Project 2015-09 Establish and Communicate System Operation Limits. It is not clear why the planning study requirements do not align with the operation requirements and require advance study of the same concern. Furthermore, this exemption presents a real risk to the system reliability. The Footnote 13 language transfers identification of this reliability risk into the real-time environment, where the tools used to identify dynamic instability do not typically exist. Regardless of whether the event actually occurs, the proposed Footnote 13 language creates a gap in the standards and exposes registered Transmission Operators to potential non-compliance under TOP-001 (and TOP-002, if the communication failure condition continues into the next operating day) for having failed to identify a stability related SOL and then operated the system to that limit.

In the real-time environment, ATC must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, ATC must operate within all System Operating Limits (SOLs) for the topology that exists at that moment, which explicitly includes the status of Protection Systems. With the loss of communication for a particular path, delayed clearing could exist for a fault and the response of the system or nearby generation may not be stable. Real-time tools would not identify the instability, and ATC would not identify the SOL to which it should have been operating. Identification of these issues should occur in the System Planning domain, where it then can be passed through to the Transmission Operator in accordance with FAC-014. The Planning environment has sufficient time to consider these scenarios to help ensure that the instability is corrected, whether that corrective action is a system reconfiguration or a new system or generator limitation for that condition.

There are additional opportunities to align terminology between PRC-005 and TPL-001 if the Standard Drafting Team continues with the use of a monitoring and alerting exemption. Some examples include "Control Center" versus "location where corrective action can be initiated" and "Open-Circuit" versus "battery continuity." Furthermore, the standard fails to address what is an acceptable monitoring period that could be used for non-redundancy or time in which corrective action would be required. Some devices are monitored in-real time, while others test less periodically, including once a day or monthly. Finally, the standard as currently written fails to address those systems that are part of non-battery-based systems.

The use of double negatives in Footnote 13 is confusing (e.g., not considered non-redundant). Consider modifying the wording of the P5 requirement to Fault plus failure of a component of a Composite Protection System which results in remote and/or delayed clearing. In this context, delayed clearing would be a delay beyond the slower of redundant systems as described above. The footnote could be simplified to state that components to be considered include protective relays, communication systems, DC supply, and control circuitry associated with the protective functions.

The redundancy of communication paths needs to be addressed. Consider the following clarification, “Communication systems are considered fully redundant if, for any single component failure such as power line carrier equipment, microwave tower, tone path, or OPGW, one communication system remains fully functional.”

ATC is concerned about the impact of mitigation of single station DC failures for stations without open circuit monitoring. Monitoring reduces the exposure to risk but cannot mitigate it. While monitoring and alerting systems are starting to become available within the industry, from ATC's perspective, they are not widely implemented. The result would be any BES facility without redundant DC supplies being tested for P5 bus section contingencies will result in delayed clearing. For the sites that fail this scenario, ATC would elect for redundant DC supplies due to future concerns about the true "redundancy" of monitored equipment. The result would likely mean building new control houses at significant cost due to space constraints at existing facilities. Finally, it is unclear as to what the appropriate evidence would be to demonstrate compliance with Footnote 13. There is no indication of what evidence type would be required to demonstrate that entities have redundancy or monitoring. Verification of redundancy of control circuitry could drive assembly of a significant number of station drawings, inventories, and other pieces of evidentiary documentation to prove redundancy. This verification has the potential to be extremely burdensome for both the industry and audit staff.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	2015_10_Comment_MH_1.docx
Comment	
See attached comments	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	

Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Footnote 13 items “b”, “c”, and “d” contain the parenthetical language “(except […] that is both monitored and reported at a Control Center shall not be considered non-redundant)”. It can be argued that monitoring and reporting these quantities at a Control Center does not adequately address the potential failure of these systems when called upon to act. I.e., just because the monitoring and reporting at a Control Center indicates that these systems are functional does not necessarily mean that they will function properly when called upon. There should be no argument that redundancy in items “b”, “c”, and “d” is more reliable than SPFs that are monitored at a Control Center; however, Peak can accept the risk-based decision and justification that, as quoted in the rationale document, “components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.”	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed language of Footnote 13, which clarifies the scope of non-redundant components.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

The follwoing comments (1 through 5) are being submitted on behalf of the City Light SMEs: Yes - Footnote 13, specifically section a, provides a clear definition of non-redundant components of a protection system.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that the clarifications are an improvement.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
The contents of Footnote 13 now provide additional clarification of Requirement expectations as it relates to non-redundant Protection Systems. However, including this level of detail in planning assessments raises concerns: 1. Is consideration of the Protection System details even possible or practical given the state of available information and modelling tools? 2. Does the complexity of the resulting models and planning assessments create an increased opportunity for incorrect results? 3. Will it essentially create a new “design” standard that will lead to increased protection system redundancy for all transmission facilities regardless of the impact on BES reliability. 4. By considering the conditions for monitoring Protection System components (e.g. trip coil, DC Supply, etc.), there is an indirect impact on existing Requirements included in PRC-005, which also consider component monitoring when establishing maintenance periodicity.	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
While ITC generally supports the current content of Footnote 13, we would suggest the following addition. Update Footnote 13d to exclude the wiring to and from the trip coil, in addition to a single trip coil when required for Normal Clearing where it is monitored and reported. Suggested update, “A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip coil and wiring that is both monitored and reported at a Control Center shall not be considered non-redundant).”	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Midcontinent Independent System Operator, Inc. (MISO) and New York Independent System Operator, Inc. (NYISO) do not join the ISO/RTO Council Standards Review Committee's (SRC) response to this question.

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 1	Con Ed - Consolidated Edison Co. of New York, 3, Yost Peter
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	
Document Name	TPL-001-5 Footnote 13 Double Negative Comment 090718.docx
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
The NYISO agrees that the removal of Req. 1, Part 1.1.2 will still meet the objective of FERC Order No. 786. We do not agree with the changes to Req. 2, Parts 2.1.4 and 2.4.4. We believe the assessment should be performed for all contingencies listed in Table 1, since all such contingencies are studied in the Operations Horizon. Not including all Table 1 contingencies in Req. 2 introduces a gap between the Near-term Planning and Operations Horizon assessments, poetentilally leading to a reliability gap. Other proposed NERC Standards, such as FAC-011-3, FAC-014-2, and FAC-015-1 are proposed to, among other things, improve the coordination between Planning and Operations. The proposed revisions here seem contrary to that intent.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
While the modifications to requirements R1.1.2, R2.1.4 and R2.4.4 are acceptable, the concerns covered by the proposed requirements R2.1.4 and R2.4.4 would be better addressed through a modification of IRO-017	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	

Comment	
We find the new language difficult to interpret. We provide the following comments for consideration to make the requirements more succinct: The language seems to indicate a new procedure, or an edit to an existing procedure is required. We do not think the requirement should stipulate a new or modification to a procedure. We suggest revising the requirement as follows (applicable to both 2.1.4 and 2.4.4): *When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages expected to produce more severe System impacts on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with outage coordination procedure(s) or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.* Additionally, the following sentence could be removed from the requirement and added to the technical rationale: *Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1."* The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We find the new language difficult to interpret, and possibly redundant. We provide the following suggestions for consideration to make the requirements more succinct. The documented outage coordination procedure or technical rationale should cover the rationale for outage selection.	

When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

Additionally –

The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 Outage Coordination, which purpose states "To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.

IRO-017 R4 states:

Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

The intent and requirements of IRO-017-1 R4 and proposed TPL-001-5 R2 parts 2.1.4 / 2.4.4 seem to overlap, potentially causing confusion.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA does not agree with the proposed revision. These studies are already performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. If issues were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an operating guide. The operational cases have a more accurate near-term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take siginificant new effort and time to complete. Outages in the planning horizon should be studied by the TP, while those in the operations horizon should be studied by the TOP.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

In our opinion, any known/planned outages of major equipment for maintenance or construction should be included in the appropriate models to be assessed for P0-P7 planning events. Therefore, Requirement 1, Part 1.1.2 needs to be retained except for the words “with a duration of at least six months”.

We propose alternative language to Part 1.1.2 as follows:

"Known outage(s) of generation or Transmission Facility (ies) scheduled in the Planning Horizon."

Modification to Part 1.1.2, as proposed above, would also allow the last bullet of Part 2.1.3 to remain as an option for a sensitivity study.

We disagree with the language proposed for new Part 2.1.4. We disagree with the phrase "selected known outages" (line 2) as we believe this is not the intent of the Commission to pick and choose which planned outages should be assessed. We disagree with the development of a "documented coordination procedure" (line 5) as Transmission Planners and Planning Coordinators do not coordinate outages. Instead, we believe that a documented methodology or collection process to obtain the outages scheduled in the Planning Horizon needs to be developed. We disagree that the proposed assessment shall be performed for only the P0 and P1 planning events (lines 8 and 9), as we do not believe these analyses are sufficient to identify areas for non-consequential load loss during times of maintenance outages. We believe that if the changes to Part 1.1.2 are included as proposed above, then much, if not all, of the proposed Part 2.1.4 can be eliminated, which would be an enhancement to the standard.

As the FERC expressed in paragraph 42 of its Order 786, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." In our opinion, the language included at the end of Part 2.1.4

(lines 13-16) regarding "Past or current studies may support the selection of known outage(s) …" continues to support the idea of developing hypothetical or speculative outages based on previous analysis of Table 1 Planning Events P1-P7. Clearly this does not meet the intent of the Commission to include only planned maintenance outages, and in our opinion goes well beyond the directive.

If Part 2.1.4 is to remain, we propose that the language be changed to something similar to the following:

"When known generator and transmission maintenance outages are planned in the Near-Term Planning Horizon, the impact of these maintenance outages shall be assessed. The known outages included in the models shall be supported with a documented outage collection methodology/procedure or technical rationale for inclusion developed by the Transmission Coordinator or Transmission Planner."

Our concerns for Part 2.1.4 also apply to Part 2.4.4. For the reasons stated above, we cannot support the changes proposed by the SDT to meet the FERC directive.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
As indicated in the Applicability section of TPL-001, applicability of this requirement falls on the PC and the TP. It should be noted that the TP does not own transmission assets under the TP fuction registration. Holding a TP accountable for knowing outage status of equipment in a planning model is nonsenscial. The outage of transmission equipment is determined by those entities requesting the outage, where the burden of proof should fall on the applicable entities providing data for building models under MOD-032-1 and not the TP. As noted in R1, planning models "shall represent projected System conditions"; the TP does not have full visibility of these projected system conditions, but expects that data submitted for building of the planning models, in accordance with MOD-032-1, is as accurate as the system being projected in each of the respective planning models. Additionally, the proposed TPL-001-5 Draft 4 language "These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration." Should be removed, since the TP does not own transmission assets.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Moving the requirement for Order No. 786 to to Requirement 2 is fine. However, MISO does not agree with the characterization of planned maintenance with respect to the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making necessary system improvements. This is more fully described in the response to question 3 below.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.

Likes 0	
Dislikes 0	

Response

Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6

Answer	No
Document Name	

Comment

The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the

purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We maintain that Planning Assessments and Operations Planning shall be coordinated. As currently proposed, the TPL standard only requires P1 events to be simulated when assessing planned outages in the Near-Term Transmission Planning Horizon. However, this is inconsistent with existing standards FAC-011-3 R3 and FAC-014-2 R6, which require the Reliablity Co-ordinator (RC) also to consider multiple contingencies when assessing these outages. Therefore, at a minimum, when the Planning Co-ordinator is assessing planned outages occurring in the Near Term Transmission Planning Horizon, they should simulate the contingencies that the RC would simulate when assessing and approving these outages, otherwise operations is held to more stringent/conservative performance than planning. Moreover, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the coordination between planning and operations. The proposed FAC-011-4 R5 requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. Hence, in order to improve this coordination between planning and operations and to eliminate any potential reliability gaps between these plans, the IESO proposes that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 should require at least the same contingencies to be assessed as part of the Planning Assessment for outage conditions as the ones identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4.	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	

Comment	
While the changes to Requirement R2 Parts 2.1.4 and 2.4.4 represent a significant improvement over the currently effective TPL-001-4, Peak has a concern related to the contingencies required for study for the outages considered in the Planning Assessment. The primary concern is the lack of continuity between planning and operations with regard to contingency analysis. Per these proposed requirements, P1 contingencies are the only contingency types required to be studied for the outage conditions. However, in the operations horizon several Transmission Operators (TOP) and Reliability Coordinators (RC) consider (and require reliable system performance for) contingencies more severe than single P1 contingencies, as specified in the RC's SOL Methodology for the Operations Horizon per FAC-011-3 Requirement R3.2, R3.3, and R3.3.1. These multiple contingencies might include certain P4, P5, or P7 multiple contingencies. If there are multiple contingencies that are required for assessment (and are required to meet performance criteria) in the operations horizon, then those same contingencies should be assessed for planned outages in the planning horizon. Excluding these contingencies from the Planning Assessments for the outage conditions creates a reliability gap between planning and operations. Under the existing language, the planner's assessment of the outages would only identify reliability problems associated with P1 contingencies, whereas, if the planners considered the same contingencies that are considered in operations, the reliability gap between planning and operations would be closed. Any identified reliability risks in the Planning Assessment would result in either rescheduling the outage or proposing solutions that could be passed on to operations. If multiple contingencies that are used in operations are not required for assessment in the planning horizon, then the outcome is an environment where operations is held to more stringent/conservative performance than planning. This presents increased reliability risks, it conflicts with good utility practice, and it detracts from the principle of "plan it like you intend to operate it, and operate it like you planned it." Furthermore, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the continuity between planning and operations. These proposed standards were posted for the 45-day formal comment period on 8/24/2018. The proposed FAC-011-4 Requirement R5 and subparts requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. If this standard passes ballot, then continuity between planning and operations would be further improved if TPL-001-5 R2 Parts 2.1.4 and 2.2.4 would require these same contingencies to be assessed as part of the Planning Assessment for outage conditions. Accordingly, Peak suggests that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 require an assessment of not only P1 contingencies, but also the additional single contingencies and multiple contingencies identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4. It is possible that these more severe contingencies are unable to meet the performance criteria in Table 1 of TPL-001. This can be addressed by relaxing the performance criteria for these contingencies during prior outage conditions, where the assessments would only require that these contingencies demonstrate that instability, Cascading, or uncontrolled separation does not occur. Such a requirement actually provides even more alignment between planning and operations, considering proposed FAC-011-4 Requirements R6 parts 6.3 and 6.4 which stipulate that the performance criteria for contingencies more severe than single P1 contingencies are that the system demonstrates that instability, Cascading, or uncontrolled separation does not occur. Peak also has a concern with the language in TPL-001-5 R2 Parts 2.1.4 and 2.2.4 that states, "System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned." Peak believes that the "or" should be "and", thus requiring the outages to be assessed against both System peak conditions and against Off-Peak conditions. If the outages are not assessed against both System Peak and Off-Peak conditions, there is an increased risk that significant reliability issued could go undetected. Peak does not believe that the determination of using System Peak versus Off-Peak conditions for this analysis should rely on engineering judgement. Alternately, the System Peak and Off-Peak language could be removed and replaced with "the range of system conditions that the System is expected to experience during the outage."	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The proposed removal of the six month minimum duration threshold for modeling planned outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 Operational Planning Assessments. The IRO-017 standard establishes the outage coordination process within the operations planning horizon, which covers the period from day-ahead to one year out. The outage coordination process includes development and communication of outage schedules, evaluating impacts and developing operating plans to mitigate outage conflicts, or rescheduling outages when necessary in order to reduce the reliability impact of the critical outage. This process ensures a more accurate modeling of expected system conditions, including information on concurrent outages.	
Likes 0	
Dislikes 0	
Response	

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The relocation and revisions to wording related to the identification and treatment of known outages in the Near-Term Planning Horizon appear to address both the FERC and industry issues and concerns.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC’s response to this question.	

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
It clarifies the requirement	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Removing Requirement 1, Part 1.1.2 makes sense as the base models should reflect the longer-term state of the system and not scheduled outages or contingency events. The changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4 are logical and allow for knowledgeable, technical rationale to determine which scheduled outages need to be analyzed. Note: references to "Near-Term Planning Horizon" should be replaced with the defined term from the NERC Glossary of Terms - "Near-Term Transmission Planning Horizon".	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	

Comments: GTC agrees in principle with the changes to Requirement 2, Parts 2.1.4 and 2.4.4. However, we recommend the following format changes and minor content changes to clarify the requirements:

2.1.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.1.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.1.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.1.4.3 The assessment shall be performed for the P0 and P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

2.4.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.4.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.4.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.4.4.3 The assessment shall be performed for the P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

One additional comment is concerning the "documented outage coordination procedure or technical rationale" by which Planning entities determine the appropriate outages to be assessed. The SDT included the following statement in the technical rationale that accompanied this posting:

"The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes."

This is a reasonable assumption but it is important to note there is no requirement for operating entities to provide this type of information to planners for all planned outages. The method which an auditor would use to determine the adequacy of a planner's procedure/rationale is unclear, in instances where planning entities do not have access to operating plans as they are produced or changed

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Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	

Answer	Yes
Document Name	
Comment	

We propose the following alternative text for Part 2.1.4: "…for the P0 and P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." Similarily we proposed the following alternate text for Part 2.4.4: "…for the P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." The System peak or Off-Peak models will normally be suitable for the Part 2.1.4 and 2.4.4 requirements. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models.

Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	
Comment	

Yes for R1.1.2 removal. - The removal is just fine, because it streamlines or simplifies R1 objective, and the sub-requirement that pertain to inclusion of known outages to near-term planning horizon cases will be addressed on future requirement R2.1.4 (for steady state) and R2.4.4 (transient stability), anyway.

Yes for R2.1.4 and R2.4.4. – The proposed requirement gives the TP the choice of selecting which known outages can be included in the assessment, which are primarily outages that may pose severe system impacts to the system only. These may prove to be helpful, because the focus of the study relies only on the selection and inclusion of known outages that may cause severe system impacts to the system.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

Response

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the Standards Drafting Team's (SDT) reconsideration of Requirement language to address the comments previously submitted by Texas RE. The changes to TPL-001-5 R2, Part 2.1.4 appear to address the circular issue of R1 pointing to R2 and R2 pointing to R1.

Texas RE still contends there should be a specific requirement for the Planning Coordinators and Transmission Planners to develop an outage coordination process with specific criteria. As currently drafted, Part 2.1.4 and Part 2.4.4 state known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure *or* (emphasis added) technical rationale by the Planning Coordinator or Transmission Planner. Texas RE's position is that a technical rationale is not sufficient and there is no Reliability Standard that requires Planning coordinators and Transmission Planners to develop an outage coordination procedure. IRO-017-1 R1 requires each Reliability Coordinator to develop, implement, and maintain an outage coordination process for generation and Transmission outages within its RC Area.

Texas RE previously submitted comments including proposed language to R1 that would require each Transmission Planner and Planning Coordinator to maintain System models that include known outages of generation or Transmission Facilities. Texas RE again recommends revising TPL-005 R1.1 as follows:

1.1 System models shall represent:

1.1.1. Existing Facilities;

1.1.2. Known outages(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected according to an established procedure or technical rationale that, at a minimum: 1.1.2.1 Establishes a criteria, supported by a technical justification, for identifying significant known outages based on MW or facility ratings; and 1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	
Document Name	

Comment
How does new 2.1.4 meet the SDT's belief stated in the Technical Rationale that there is an "implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon." What is the measurement of whether the Technical Rationale developed under 2.1.4 is acceptable – simply that is not based on duration of the outage? How does having a documented outage coordination procedure satisfy the need for performing TPL analysis? Most entities already have such a process that is totally unrelated to TPL analysis. While it may be implied, the documented outage coordination procedure does not explicitly state that any modeling or contingency analysis is required.

Likes 0	
Dislikes 0	

Response

3. Do you agree with the proposed revisions to TPL-001-4?	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp does not agree with the proposed removal of Requirement 1, Part 1.1.2 and changes to Requirement 2, Parts 2.1.4 and 2.4.4 for the reasons stated in question 2 above. PacifiCorp agrees with all other proposed revisions to TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Yes and no. See comments provided for questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

As stated in our response to Question #1, AEP remains concerned by the increased complexity of Footnote 13 driven by its excessive detail. The version of Table 1 that is currently in effect is clear in its intent and application, however, we believe that Footnote 13 as currently proposed actually *removes* the clarity that was once there.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
SDG&E agrees with all revisions to TPL-001-4 except those related to P5 planning events for non-redundant components of a Protection System identified in footnote 13.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We maintain that the Contingency event that represents a 3 ph fault plus a failure of a non-redundant component of a Protection System remains a reliability concern and reiterate that the SDT's alternatives offered in Draft #1 and Draft #3 would address it: • Keep the 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events, but require a Corrective Action Plan when Cascading is identified. • Move the 3 ph fault + SPF in Protection System event to Table 1 Steady State & Stability Performance Planning Events and create a new P8 category. The only System performance requirement that should apply to P8 is that Cascading shall not occur and a Corrective Action Plan should be required when Cascading is identified.	

The existing evaluation (except to separate breaker failure from the SPF in Protection System event) brings us back to square one.	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
In the Extreme Events portion of Table 1, the use of the NERC defined term "Normal Clearing" is not sufficiently clear or could be misapplied. A composite protection system can be made up of redundant systems with significantly different clearing times. Failure within a redundant composite protection system can be interpreted as "Normal Clearing" based on the NERC definition of a "Misoperation". Using this definition, "Normal Clearing" would occur without providing clearing fast enough to meet stability requirements. Steady State and Stability Performance Extreme Events should be evaluated by simulating "worst case clearing time" of the composite protection system for the element(s) unless otherwise specified. The use of the term "Delayed Fault Clearing" in the Stability Items 2e through 2f of the Extreme Events portion of Table 1 could be interpreted differently based on the NERC definition of "Delayed Fault Clearing". The NERC definition of "Delayed Fault Clearing" seems to apply to failures of an entire composite protection system, whereas clearing occurs via breaker failure or some remote clearing after an intentional delay. Using this interpretation of the definition, the failure of a portion of a redundant system which results in a slower clearing time would not meet the definition of "Delayed Fault Clearing", but could still result in clearing that does not meet stability requirements. Stability Items 2e through 2f of the Extreme Events portion of Table 1 should be studied under conditions where failure of a non-redundant component results in "worst case clearing time" for the composite protection system of the element(s).	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
For the same reasons stated in question 2. BPA believes that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See comments for question 2.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment
MISO supported the changes previously proposed by the SDT to create the P8 contingency. Given that a Corrective Action Plan is needed to address instability or cascading resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, the best way to achieve this requirement is through the creation of a P8 contingency rather than extreme events. Therefore, MISO agrees with the proposed P8 event. MISO would also support expanding the P5 contingency definition to include both a phase-to-ground fault and a three-phase fault as well should the Standard Drafting Team prefer to expand the P5 contingency definition rather than establish a new P8 event. The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making necessary system improvements. Adequacy, reliability, robustness, and resilience include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single transmission facility has been removed from service for planned maintenance or other purposes. All transmission facilities require planned outages from time-to-time to facilitate maintenance and repair work that cannot be performed hot, to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility, or for other purposes. Therefore, the eventual occurrence of a future planned outage on a transmission facility is certain and “known”, not “hypothetical”, only the timing and duration of the future outage could be considered uncertain or “hypothetical”. If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy, robustness and flexibility to accommodate maintenance requirements in general. In FERC Order 786, the Commission indicated the following at PP 41: “We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.” (emphasis added) It is “known” that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the proper planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient robustness and resilience to accommodate the planned maintenance flexibility during off-peak periods that will be required regardless of whether or not such activity has been scheduled at the time the planning assessment is conducted. While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and robustness to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate a planned outage (which is generally considered unacceptable) or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedules planned outages when they are needed without sacrificing reliability or load continuity. A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This contingency definition, which would be applicable only for non-peak conditions where planned maintenance is normally performed, could be

implemented as a P2.1 contingency, followed by system adjustments (but no load shed), followed by a P1 contingency. With this new contingency added, the system would be planned to accommodate the planned outage of any one system element (transmission or generation element) during off-peak periods while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. Use of the P2.1 contingency as the maintenance contingency ensures continuity of service to load for the maintenance outage, which aligns with how the system would be operated. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, robust, resilient, and reliable in the future.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
The standard should be revised to represent the true intent for this standard, which is to hold the PC and TP accountable for assessing the state of the transmission system under specific scenarios, determine deficiencies, and act to correct those deficiencies. Requirements outside of the control of the TP are not an effective tool to determine if the intent of those requirements has been met. The TP can only assume that transmission equipment outages that represent a future timeframe (year one or year two), have been submitted by the entity requesting the outage, and are correct.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
See proposed changes to Requirements 1 (Part 1.1.2) and 2 (Parts 2.1.4 and 2.4.4) above.	

Clarification in needed on 'Table-1 – Extreme Events Second Column Stability Item 2f'.

This should be changed to 3-phase close-in fault on Transmission circuit with failure of a non-redundant component of a Protection System result in Delay Fault Clearing.

The FERC Order 754 study only looked at close-in line and bus faults with remote clearing. For end of line 3-phase faults, fault detection is unlikely with a failure of a non-redundant battery due to in-feed effect. It is not possible to run a stability study with this indeterminate state. The requirement as written will require installation of redundant batteries or battery monitors at all BES substations. If this is the case corrective action plans may take years to complete. Given the low probability of a battery failure concurrent with a 3-phase end of line fault, was this the intent of the standard? Also, for end of line faults can credit be given for the chargers ability to trip?

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA believes that the proposed changes to Footnote 13d creates a significant cost impact for a very small probability event. TVA believes that the proposed changes to Requirement 2, Parts 2.1.4 and 2.4.4 would add no value and create siginificant new effort and time to duplicate operations studies.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

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Please see comments in question 1 and 2 above.

Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):

Requirement 4.1 states that “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1…..” Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

Additional Comment for consideration, related to clarification of the Standard:

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

Likes 0	
Dislikes 0	

Response

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1

Answer	No
Document Name	

Comment

See NSRF comments

Likes 0	
Dislikes 0	

Response

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No

Document Name	
Comment	
NV Energy feels it is prudent to require a corrective action plan resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, and should therefore not be considered an extreme event, but rather a planning event. NV Energy did not agree with the changes previously proposed by the SDT to create a new P8 contingency, but would support expanding the P5 event to include a three phase fault or a L-G fault, or replacing the L-G fault type with a three phase fault.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
Please see comments in question 2 above regarding known outages. The current title of the technical rationale document is misleading as it could be interpreted as the technical rationale for single points of failure only, instead of TPL-001-5 as a whole. We request that the title of the technical rationale be changed to “TPL-001-5 Technical Rationale.” The language in 2.1.5 should be modified to align with 2.4.5 as shown below: *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 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.* Additionally, per the SDT’s response to the last round of comments submitted, please add language in the technical rationale to clarify on what is meant by the spare equipment strategy. For reference, below were the comments submitted – *Does “spare equipment strategy” mean the existence of at least a single spare for major transmission equipment that has a lead time of more than one year; and does Requirement 2.4.5 imply that the existence of such a spare would eliminate the need to assess the impact of the possible unavailability of such equipment on System performance? If so, then Requirement 2.4.5 should be written this way.* *As currently written, Requirement 2.4.5 lacks clarity. Every reasonable “spare equipment strategy” for equipment with a lead time of one year or more could result in the unavailability of such equipment; it is a matter of probability. For example, an Entity with 100 large power transformers could have*	

a spare transformer strategy of maintaining one system spare. However, it is possible that two transformers could fail during time span of one year. With only one spare, the Entity would be exposed to operating the system for up to one year with one less transformer than designed. Even if the Entity has four (4) spares, it is still possible that five (5) transformers could fail during one year (albeit with much lower probability), which would leave the Entity similarly exposed. Greater clarity is required for Requirement 2.4.5, as is more criterion development.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
No. Westar Energy and Kansas City Power & Light incorporate by reference their response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The addition of new single point of failure of selected non-redundant Protection System Components to the P5 contingency event category seems appropriate. Elimination of the P8 contingency event category and moving the new single point of failure of selected non-redundant Protection System Components to the Extreme Events category seems appropriate. The language in Footnote 13 is still a concern, as noted in ATC's comments on Question 1 above.	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
See comments for question 1.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the proposed revisions as drafted.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Seattle City Light agrees with the proposed revisions to the TPL-001-4. The definition of the non-redundant components of protection system is also adequate and provides clarity to the definition of non-redundant components of protection system.	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
We agree with the proposed revisions except as noted on this Comment Form.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	

We agree with the proposed revisions except as noted on this Comment Form.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC thanks the SDT for their work on developing this revision to the TPL-001 and agrees with the work they have done so far. ITC does not believe though that the language for the Requirements 3.5 and 4.5 for the evaluation of the non-redundant component of a protection scheme goes far enough. While it does require industry to evaluate the consequences of the configurations, it does not require a Corrective Action Plan be developed for any significant affect to the transmission system. ITC believes a CAP should be required.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Studying the steady-state and dynamic impacts of events involving the non-operation of single elements of a Protection System as well as notable scheduled outages is worthwhile in order to maintain transmission system reliability.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes

Document Name	
Comment	
It is appropriate	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE’s response to #2.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed implementation plan?	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The first timeframe following FERC's approval of TPL-001-5 needs to be 5 years, rather than 3 years, to perform all the required tasks (e.g., make model changes; develop the new Footnote 13 contingencies; perform the new known outage, long lead time, P5, and Extreme event analyses; and develop CAPs for non-P5 contingency system deficiencies). The timeframes of 2 years and 4 years to complete the other required tasks seem acceptable.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SSRG notes that after the 48-month implementation sunset provision has expired, the implementation plan will not provide an entity with sufficient time to implement a Corrective Action Plan (CAP) identified in future annual planning cycles. For example, a CAP that identifies a facility that will require longer than one year to construct will not be in-service by the next annual planning cycle, which will impact the Planning Coordinator's (PC) the ability to meet the Table 1 performance requirements for the next annual planning assessment. In other words, an unintended and unavoidable consequence of the requirement may be a violation of R2.7 through no fault of the PC performing the annual study and preparing the CAP. A solution to the issue would be to include an exception in Section 2.7.3 or create a new Section 7.2.4 that alleviates the need to meet the Table 1 performance metrics for subsequent planning assessments when P5 events identify a capital project as a CAP and no other mitigation can be achieved. The exception would be extended until the capital project can be placed into operation.	
Likes 0	
Dislikes 0	
Response	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Depending on the different mitigations, it may take longer to implement.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	

- PJM planning procedures do not allow for redispatch to address reliability criteria violations. Based on this, PJM has some concerns regarding requirements to fully implement Corrective Action Plans in accordance with the identified schedule. As the RTO, PJM does not have control over the construction schedule, and relies on individual Transmission Owner to complete construction and implement enhancements by the required in service date detailed in the Corrective Action Plan.

- The sentence "The first annual Planning Assessment shall be completed in accordance with TPL-001-5, but without CAPSs for revised P5, by this date." in Figure 1 of the Implementation Plan could use some clarification. PJM in concerned that the sentence implies that revised P5 events, while not requiring a CAP, still need to be included in the Planning Assessment at the t+36 Point on the timeline. PJM Proposes the following revisions to clarify that revised P5 events are not required for inclusion in the assessment during this first 36 month period: “The first annual Planning Assessment (excluding revised p5 events), shall be completed in accordance with TPL-001-5, but without CAPs for revised p5, by this date.”

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy does not support the proposed Implementation Plan. Without knowing at this time the potential size and scope of the work that will be necessary for implementing the CAPs, we cannot agree on the 48 month portion of the Implementation Plan. These corrective actions will likely involve improvements to protection systems for BES elements and these require system outages to critical lines that are only made available during low-load periods that will extend the overall time required to complete the CAP. We disagree with assigning an implementation period to an unknown scope of work. We suggest the SDT consider a flexible Implementation Plan with phases that can be assessed depending on the size and scope of work.

Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	

It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.

Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	
Comment	

Since we have concerns with some proposed revisions, (please see comments in question 1 and 2 above) we feel it is premature to consider a specific implementation plan.

Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	
Comment	

While the implementation timelines to study and develop CAPs are reasonable, TVA does not agree with the implementation timeline for completing CAPs to address the modified P5 events. These changes will require extensive work in order to make protection systems completely redundant for these events, requiring switch houses in some cases. If several switch houses are required, the proposed implementation plan would not provide adequate time to coordinate extensive outages and complete the corrective action plans.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
We do not agree with the proposed edits or non-TP related requirements, hence we do not agree with the proposed implementation plan, at this time.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We believe the changes recommended above need to be made before we agree with an implementation plan.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
More time is needed to implement the proposed changes.	

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
As we have mentioned before, SDG&E does not agree with the changes related to P5 planning events for non-redundant components of a Protection System identified in footnote 13. Unfortunately, a great deal of the changes to the implementation plan are to allow time for the Transmission Planners to coordinate with protection engineers on addressing these new requirements.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
We believe that the proposed implementation plan is reasonable. A significant amount of protection and controls related data and design drawings will have to be accessed and reviewed in order to facilitate the ability to study the required additional dynamic simulations.	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SCL agrees with the implementation plan and the timeline given to accomplish the plan.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The implementation plan profides sufficient time to perform studies and coordinate CAPs with external entities to meet compliance with TPL-001-5.	

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	
The legal framework in Manitoba Hydro's jurisdiction does not permit the use of an implementation plan. The proposed NERC 9-year implementation plan appears reasonable.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the SDT's attempt to clarify the implementation plan and the timeline provided is helpful. Texas RE recommends explicitly saying which requirements are applicable in the Compliance Date and Initial Performance date sections. Based on the words written (not on the visual timeline), Texas RE understands the IP as follows:

- First calendar quarter 36 months following regulatory approval.
  - The effective date of the standard is the first day of the first calendar quarter 36 months following the effective date of the applicable governmental authorities order approving the standard. This date serves as a starting point for the implementation plan.
  - In accordance with the Initial Performance section, applicable entities must complete the planning assessment without CAPs by the effective date of the standard, or 36 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes there is no requirement mentioned. **In the interest of clarity and not being vague Texas RE strongly recommends the implementation plan specify which requirement this date refers to.**
  - 60 months following regulatory approval.
    - In accordance with the Initial Performance section, applicable entities must develop any required CAPs 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 b, c, and d, or 36 months plus 24 months, or 60 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes this is also indicated in the Compliance Date section, **which is redundant and could cause confusion**.
  - 108 months following regulatory approval
    - In accordance with the Compliance Date section, for CAPs developed to address failures to meet Table 1 performance requirements for the p5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, or 36 plus 72, or 108 months following the effective date of the applicable governmental authority's order approving the standard.

Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp believes that the proposed revisions to TPL-001-4 to model known outages with a duration of less than six months in the annual Planning Assessment are not a cost effective way of meeting FERC directives in Order No. 786 as these studies are already being performed in TOP-003 and IRO-017 Operational Planning Assessments. PacifiCorp agrees that the proposed revisions to TPL-001-4 along with the Implementation Plan are a cost effective way of meeting FERC directives in Order No. 754 addressing reliability issues associated with single points of failure in protection systems.	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
BPA believes that the revision to the standard and the implementation plan do not adequately address industry concerns about the costs needed to plan and construct a project for a planned maintenance outage of short duration. Those planned maintenance outages will be coordinated ahead of time according to outage planning processes. It is not cost effective to plan and construct a project for a planned maintenance outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes. Requiring a low-probability, single-point-of-failure of protection systems to be analyzed as a Planning Event is beyond prudent planning. The proposed changes could be a very-significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System. The proposed changes to the standard would require industry to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP or PC to decide whether mitigating possible Cascading is cost effective. The cost effectiveness document falls short of providing any substantive cost effectiveness analysis and is more like a repeat of the proposed changes to the requirements & footnote 13.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Since the standard does not meet the objective of Order No. 754, the question of whether or not it is cost effective is moot.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	

FERC directives, cost effective or not, are a direct order of action which in accordance with the directive, if the directives determine that transmission system deficiencies exist being detrimental to state of the transmission system, those deficiencies should be acted on and corrected. Allowing more time (+12 months to all milestones) for the implementation as a result of these changes, may minimize the financial impact.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA does not believe the proposed changes to Footnote 13d are a cost effective approach. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.

Likes 0	
Dislikes 0	

Response

Robert Ganley - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

While the proposed revisions to TPL-001-4 along with the Implementation Plan may be a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754 in terms of corrective action plans, the proposed revisions will present a very significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System. This incremental burden will have adverse cost impacts.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System.

It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.

Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	

The proposed addition of “non-redundant” components of a Protection System, in particular Footnotes 13.b. and 13.d., to this Standard may add significant resource and financial burden to Transmission Owners (TOs) that in all cases may not provide a benefit to BES reliability. Although a planning standard, the Requirements as proposed may indirectly result in TOs expanding internal “design” standards to implement redundant Protection Systems on all transmission facilities regardless of the impact on BES reliability. As an alternative approach, the SDT could consider addressing the FERC directives by expecting planning assessments be performed with the assumption that all Protection Systems are non-redundant, and then when concerns are identified, the entity would confirm that there is a redundant Protection System in place or develop a CAP to address the non-redundant Protection System. Other than increasing the scope of the planning assessments, this type of process to investigate concerns as they are identified, might eliminate the initial administrative burden on collecting detailed Protection System information and building models with sufficient detail and accuracy. It would also avoid the unintended consequence of TOs upgrading all transmission facilities with non-redundant Protection Systems, regardless of the impact on BES reliability.

Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC does not believe it is cost effective to study the consquences of non-redundant protection devices and not require a CAP for these scenarios should their affect on the transmission system be significant and detrimental. ITC believes if the results of a study of these types of events show this, a CAP should be required.	
Likes 0	
Dislikes 0	

Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
It is not clear whether this will be cost effective at this point.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
While the modifications to requirements R1.1.2, R2.1.4 and R2.4.4 are acceptable, the concerns covered by the proposed requirements R2.1.4 and R2.4.4 would be better addressed through a modification of IRO-017.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	

No. Westar Energy and Kansas City Power & Light's incorporate by reference their response to Question 1. Without the exception offered in response to Question 1, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC has concerns about that current Implementation Plan and cost-effectiveness of the proposed revisions to TPL-001-4. The current proposed language for Footnote 13 leaves uncertainty in applicability and potential gaps in studies through the use of exemptions, as noted in ATC's comments on Question 1 above. Furthermore, the uncertainty in the amount evidence to prove redundancy and/or monitoring has the potential to be a significant work effort. Regarding studies that are to be performed, the proposed TPL-001-5 standard and Implementation Plan are cost-effective, with the exception being the first 3-year timeframe of the Implementation Plan, as noted in ATC's comments on Question 4 above.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
The proposed revision and 9-year implementation plan may be a reasonable way of meeting the FERC directive. However, MH feels that the analysis and mitigation of 115 kV and 138 kV stations is burdensome and likely expensive without necessarily improving overall BES reliability. As a result, we propose the following: 1. Implementing a risk based assessment to identify critical facilities of concern rather than making full protection redundancy a bright line requirement for all BES facilities.	

2. For P5 definition of HV limit should be considered from 200 to 299kV.

GENERAL COMMENT

MH will be unable to adopt this standard as a NERC standard based on legislative restrictions in Manitoba. However, changes proposed in TPL-001-5 that are acceptable to MH would be adopted in a future Manitoba standard, MH-TPL-001-5.

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner.

Likes 0	
Dislikes 0	

Response
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	Yes
Document Name	

Comment
It meets both FERC directives. Whether it’s cost effective or not remains to be seen.

Likes 0	
Dislikes 0	

Response
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE

Answer	Yes
Document Name	

Comment
OKGE supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.

Likes 0	
Dislikes 0	

Response
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
The SSRG supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

We believe that meeting FERC Order 786 has nothing to do with cost effectiveness. While we agree with the concept of requiring redundant system protection elements only where they are needed, per Order 754, the process of having system protection engineers perform analysis for each BES facility to determine clearing times for failures of non-redundant system protection elements is burdensome and will require significant additional man-hours.

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No comment of opinion on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	
Comment	
Section 2.1.4 – Capitalize "c" in Planning coordinator Section 2.4.5 – delete "Based upon this assessment" at the beginning of the second sentence to be consistent with R2.1.5	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

Additional comments received from Mike Smith - Manitoba Hydro (via attachment link in the comment report)

MH recommends the following changes to the footnote 13 of Table 1 (new text in red, removed text in green strikeout).

b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communications system that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant);

c. A single station dc supply and it's DC distribution circuits associated with protective functions required for Normal Clearing (except a single station dc supply and it's DC distribution circuits that is both monitored and reported at a Control Center for both low voltage and open circuit shall ~~not~~ be considered ~~non-~~redundant);

d. A single ~~control~~ trip circuitry ~~(including auxiliary relays and lockout relays)~~ associated with protective functions, from the ~~dc supply~~ protection relay through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip circuit and coil that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant).

e. A single auxiliary tripping or lockout relay associated with protection tripping;

Rationale:

In footnote-13c, it is not clear whether or not monitoring is a satisfactory way to address only the SPF of the main supply (batteries and main bus) or also of the various branch circuits involved in DC distribution. The proposed changes allow for monitoring exceptions for DC Distribution and components of the trip circuit which are low probability items for failure similar to the previous exceptions permitted for DC supplies, communications and trip coils. We would also like to propose to put auxiliary trip relays and lockout relays on their own line to make it 100% clear that they must be considered in a SPF analysis.

Comments received from Jeremy Voll - Basin Electric Power Cooperative (via attachment link in the comment report)

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

   ☐ Yes

   ☒ No

   Comments: Please consider the following:

   Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, "shall be considered redundant".

   Add wording like, "Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance." at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the "Clarification: Is backup clearing redundant?" section on page 3 of the Technical Rationale with a different question and discussion like the following:

   Clarification: "When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?"

   If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one of these protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- “Voltage and current sensing devices of a Protection System are not considered.” Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- “Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant”. Discussion of this matter is only in the Technical Rationale (p. 5) right now
- “The reclosing relays of a Protection System are not considered.” This matter is not presently discussed in the Technical Rationale.
- “Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant.” This matter is not presently discussed in the Technical Rationale.
- “Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant.” This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

☒ Yes

☐ No

Comments:

The revisions appear to address both the FERC and industry issues and concerns.

3. Do you agree with the proposed revisions to TPL-001-4?

☒ Yes

☐ No

Comments:

4. Do you agree with the proposed implementation plan?

☐ Yes

☒ No

Comments:

It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost-effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

☐ Yes

☒ No

Comments:

See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System.

It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.

Comments received from Chris Scanlon – Exelon (via attachment link in the comment report)

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

☐ Yes

☒ No

Comments: For clarity of purpose the double-negatives should be removed from 13b, 13c, and 13d. Consider: "…*that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant)"*

Consideration of Comments

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5 Draft 4
Comment Period Start Date:	7/30/2018
Comment Period End Date:	9/14/2018
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 AB 3 ST 2015-10 Single Points of Failure TPL-001-5 Implementation Plan AB 2 ST

There were 51 sets of responses, including comments from approximately 148 different people from approximately 96 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director of Engineering and Standards Howard Gugel (via email) or at (404) 446-9693.

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

3. Do you agree with the proposed revisions to TPL-001-4?

4. Do you agree with the proposed implementation plan?

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Standards Review Committee	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
					Helen Lainis	IESO	2	NPCC
					Michael Puscas	ISO New England, Inc.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	Eversource Energy	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter state	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mike Kidwell	Empire District Electric Company	1,3,5	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					John Rhea	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

1. *With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?*

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP remains concerned by the increased complexity of P5 due the expansion of footnote 13. As written, this footnote requires one to consider a variety of scenarios, including backup zone 2 clearing of a transmission line for pilot relay or pilot communication failure, a breaker failure scenario initiated by trip coil failure (often the same as P4), or remote clearing of a station such as would occur upon a non-redundant bus differential failure.

In order to avoid having to evaluate zone of protection clearing times for every conceivable protection outage condition and document the “consideration” of each of the sub-items under footnote 13, AEP suggests a more generalized P5 event description by adding the text “or Remote (Delayed) Fault Clearing.” As a result, it would then read: “Delayed Fault Clearing ***or Remote (Delayed) Fault Clearing*** due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator, 2. Transmission Circuit, etc.”

This would continue to make use of the existing glossary term…

Delayed Fault Clearing – Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.

This existing term covers zone 2 backup clearing of transmission lines as well as being duplicative of P4 CB failure scenarios. As a result, a new definition is necessary to cover a gap:
Remote (Delayed) Fault Clearing – Fault clearing necessary to be accomplished at stations one removed from a faulted station bus or other faulted station equipment as a consequence of a protection system single point of failure at the faulted station.

This new term is necessary because relays may not be set with an intentional time delay for clearing remote station faults, and remote clearing may be necessary for non-redundant bus differential schemes. Whether “Delayed” is included in this new term may be

immaterial since, while clearing times may be long, there may be no intentional delay, just inherent delay. Footnote 13 could then removed from the draft standard, and instead, be added to the technical supplement to the standard. The would explain the possible causes of delayed clearing or remote delayed clearing, instead of rigorously having to be part of the standard and introducing what we would regard as unnecessary compliance burdens.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. While the SDT recognizes that Footnote 13 has become more detailed as a result of the proposed revisions motivated by the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations, the SDT does not believe it has become unnecessarily complex. On the contrary, the SDT considers that the proposed revisions to Footnote 13 has brought increased attention to assessment concerns that pre-existed in TPL-001-4 and has clarified considerations about non-redundant components of a Protection System, while facilitating flexibility in addressing the non-redundant components of a Protection System reliability concerns. The SDT appreciates the suggestion to propose a new NERC Glossary of Terms definition, but believe this is unnecessary given the existing definitions of Normal Clearing and Delayed Fault Clearing. To the point, the SDT considers that the "intentional delay" included in the Delayed Fault Clearing definition is both intentional and inherent to the design of backup protection. The SDT has added additional narrative to the Technical Rationale to clarify this topic. The SDT has suggested potential approaches to addressing the challenges of coordinating considerations regarding non-redundant components of a Protection System between planning and protection personnel in the Technical Rationale. Thank you, again, for your comments.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	

Footnote 13 is unnecessary. The available powerflow software doesn't simulate protection system equipement (relays, communication systems, dc supplies or control circuitry). The software simulates the transmission network. A protection system failure is simulated by making assumptions about the system's response to the failure and then simulating it. Adding specific equipment to the standand does change the simulation. Without actual protection equipment in the model, it falls on the engineer to make the correct assumptions when doing the simulations. As it should be.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT disagrees that Footnote 13 is unnecessary and considers its continued existence is consistent with the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations. The SDT agrees that appropriate and accurate fault magnitude and clearing times, as well as sequencing and causality of tripped equipment are key to properly simulating the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Moreover, the SDT considers that Footnote 13 directs the personnel performing the required assessment to which non-redundant components of a Protection System should be considered when formulating the proper simulation assumptions. Thank you, again, for your comments.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
The phrase "comparable Normal Clearing times" is not consistent with the existing definition of "Normal Clearing" found within the Glossary of Terms Used in NERC Reliability Standards. Additionally, "comparable Normal Clearing times" is not sufficiently clear to allow consistent interpretation for purposes of enforcing the standard.	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that Footnote 13 reference to Normal Clearing times is wholly consistent with the NERC Glossary of Terms definition and clearly refers to the time normally expected with proper functioning of the installed protection system that operates as designed to clear a fault. The SDT considers that the usage of “comparable” in Footnote 13 offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System. Additionally, the SDT intent in using comparable in Footnote 13 is explained in the Technical Rationale. Thank you, again, for your comments.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Footnote 13 does not include all of the applicable single points of failure addressed by 754, such as instrument transformers, and in some cases, includes aspects that do not represent single points of failures, such as redundant breaker trip coils. With regard to breaker trip coils, the lack of two trip coils in a circuit breaker increases the potential for a breaker failure issue (P4), but does not create a relay failure issue since the absence of redundant trip coils would not prevent initiation of breaker failure for failure of a single trip coil.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT has specifically addressed the omission of voltage or current sensing devices from Footnote 13 in the Technical Rationale, consistent with the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report and recognizing that these devises have a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure.	

The SDT has emphasized that trip coils, as well as all other parts of the single control circuitry associated with protective functions from the dc supply required for Normal Clearing should be included during consideration whether a single control circuitry is a non-redundant component of a Protection System. This emphasis is intended to highlight that a SPF in the single control circuitry, regardless of which part of the single control circuitry is the SPF, may cause the single control circuitry to not operate to operate for Normal Clearing and, thus, must be properly simulated as a Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. A substantial treatment of the single control circuitry is made in the Technical Rationale, as well as specific discussion about Table 1 Planning Events P4 versus P5. Additional language about single and dual trip coils has been added to the Technical Rationale. Thank you, again, for your comments

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA agrees with the contents of Footnote 13a, b, and c. However, TVA believes Footnote 13d represents a significant cost impact for a very small probability event. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that Footnote 13d is consistent with the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations. The SDT considers that the probability of failure for a non-redundant component of a Protection System should not be confused with the severity of failure to meet System performance requirements of Table 1. The SDT has emphasized in the Technical Rationale that Footnote 13 directs which non-redundant components of a Protection System should be considered when simulating the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Footnote 13 does not prescribe a level of redundancy for the System, nor does it prescribe	

Corrective Action Plans for non-redundancy. To the point: the Table 1 Planning Event P5 prescribes the required System performance given failure of a non-redundant components of a Protection System. The SDT considers that the proposed Footnote 13d offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5. Thank you, again, for your comments.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We suggest to clarify the wording for b), c) and d). The word “except” in parenthesis is awkward. This word perhaps could be replaced with “An exception is”…..	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear. Thank you, again, for your comments	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
Footnote 13a:	

The word "comparable" in footnote 13a requires additional clarification. The Technical Rationale contains conflicting explanations of what is meant by "comparable Normal Clearing times". In the "Clarification: Is backup protection redundant?" section it appears that a secondary relay would not be considered redundant as the clearing times are not exactly the same as the primary relay. However, in the section titled "Clarification: What is comparable and what is not comparable for purposes of footnote 13?" it appears that slightly slower secondary relaying would be considered redundant if its results in "fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements". LES recommends modifying the Technical Rationale to clarify the drafting team's intent or else consider modifying footnote 13a to instead state "...that provides comparable Normal Clearing times **(e.g. piloted primary relay and non-piloted secondary relay with different Normal Clearing times)"** to ensure comparable isn't mistaken to mean having identical Clearing times.

Footnote 13c:

Is it the Standard Drafting Team's intent to consider all substations that don't have either open circuit monitoring on a single battery bank or two battery banks as non-redundant? LES feels the lack of open circuit monitoring as described in footnote 13c is too restrictive to consider a single station DC supply as non-redundant. Although the Technical Rationale section titled "Clarification: Is a battery charging system appropriate redundancy for the battery?" indicates a battery charger "may not be of sufficient power to source current necessary to operate one or more breakers", LES feels the individual utility should be permitted to analyze each substation configuration to determine if an open circuit does in fact constitute a non-redundant DC supply.

Additionally, is it the Standard Drafting Team's intent that non-redundant DC supply be modeled as an entire substation outage? This seems to be the case based on the statement "prevent the operation of all local protection" within the section titled "Clarification: Why are DC supplies addressed?". However, this is not realistic during an open circuit or low voltage situation as the relays would still be operational and only the backup protection for one line or bus section would operate during a transmission line fault. Additionally, the open circuit monitoring requirement seems unnecessary as PRC-005 provides adequate testing for open circuits. Based on this, LES recommends "open circuit" be excluded from the footnote or else additional detail added to allow for analysis of substation configuration and DC supply capability during an open circuit condition.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the usage of "comparable" in Footnote 13 offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System. Additionally, the SDT intent in using comparable in

Footnote 13 is explained in the Technical Rationale. While the SDT disagrees that the Technical Rationale describes comparable Normal Clearing times as needing to be identical, the SDT has added a clarification section to the Technical Rationale to clarify this point.

The SDT revised Footnote 13c consistent with the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations. The SDT considers that the revisions to Footnote 13c allow sufficient flexibility in addressing the non-redundant components of a Protection System reliability concerns. The SDT has addressed this topic, as well as Footnote 13c considerations of open-circuit dc supply extensively in the Technical Rationale.

Thank you, again, for your comments.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Comments: Please consider the following:

Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, "shall be considered redundant".

Add wording like, "Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance." at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the "Clarification: Is backup clearing redundant?" section on page 3 of the Technical Rationale with a different question and discussion like the following:

Clarification: "When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?"

If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one of these protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- "Voltage and current sensing devices of a Protection System are not considered." Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- "Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant". Discussion of this matter is only in the Technical Rationale (p. 5) right now
- "The reclosing relays of a Protection System are not considered." This matter is not presently discussed in the Technical Rationale.
- "Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant." This matter is not presently discussed in the Technical Rationale.
- "Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant." This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and

corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.

Likes 0	
Dislikes 0	

Response
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear. The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT asserts that consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, if after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance. The SDT has revised Footnote 13 to be explicit about what non-redundant components of a Protection System shall be considered; the SDT disagrees that it is necessary to specify equipment that need not be considered in Footnote 13. The equipment omitted from Footnote 13 consideration is described in the Technical Rationale. Additionally, revisions to the Technical Rationale to address items such as reclosing circuitry and trip coils have been affected. The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which

Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5.

Thank you, again, for your comments.

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
The Technical Rationale does not clarify whether two communication systems must use to separate communication paths (e.g. not the same power line carrier line, single OPGW, microwave tower, tone path, etc.) to qualify as non-redundant systems. The Technical Rationale does not clarify whether control circuitry must use separate paths (e.g. not the same control panel, wire tray, etc.) to qualify as non-redundant circuitry.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT has revised Footnote 13 to be explicit about what non-redundant components of a Protection System shall be considered. The SDT considers that this, along with supporting material in the Technical Rationale, are sufficient for the applicable entities to conduct their own considerations of their own Protection System details for the purpose of assessing Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Thank you, again, for your comments.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy requests further clarification on the use of the term “monitoring” in Footnote 13 item b. Is it the drafting team’s intent, that “monitoring” should be continuous in nature, or would a once a day “check back” of the protection system meet the drafting team’s intent for monitoring? More clarification is needed on this point.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT has revised Footnote 13 to be explicit about what non-redundant components of a Protection System shall be considered. The SDT considers that this, along with supporting material in the Technical Rationale, are sufficient for the applicable entities to conduct their own considerations of their own Protection System details for the purpose of assessing Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT has made reference to the “within 24 hours of detecting an abnormal condition” recommendation of the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations in the Technical Rationale. Thank you, again, for your comments.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk. To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase “shall not be considered non-redundent” to “shall be considered redundant” at the end of the sentence for 13b, 13c, and 13d.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear. Thank you, again, for your comments.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. Please see the SDT response to MRO NSRF comments. Thank you, again, for your comments.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. Please see the SDT response to MRO NSRF comments.

Thank you, again, for your comments.

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	No
Document Name	

Comment

MidAmerican Energy Company supports comments submitted by the MRO NERC Standards Reveiw Forum (NSRF).

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. Please see the SDT response to MRO NSRF comments.

Thank you, again, for your comments.

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins

Answer	No
Document Name	

Comment

The term “comparable Normal Clearing times” as stated in 13.a. may cause inconsistent interpretation between entities and auditors as to what is considered comparable. Consider replacing “…without an alternative that provides comparable Normal Clearing times” with wording used in the Technical Rationale such as “…without an alternative that clears the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly.”

Consider replacing the double negative wording in 13.b, 13.c and 13.d ("shall not be considered non-redundant") with "shall be considered redundant."	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the usage of "comparable" in Footnote 13 offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System. Additionally, the SDT intent in using comparable in Footnote 13 is explained in the Technical Rationale. The SDT has added a clarification section to the Technical Rationale to clarify this point. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear. Thank you, again, for your comments.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
We suggest that the term "shall not be considered non-redundant" be removed in subsections b), c), and d). Also, we suggest changing the term "except" to "unless" for the three sections. In d), regarding control circuitry, we suggest the following language change: *(unless a single trip coil that is both monitored and reported at a Control Center if it is the only single point of failure in the control circuitry).*	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear. The SDT has emphasized that trip coils, as well as all other parts of the single control circuitry associated with protective functions from the dc supply required for Normal Clearing should be included during consideration whether a single control circuitry is a non-redundant component of a Protection System. This emphasis is intended to highlight that a SPF in the single control circuitry, regardless of which part of the single control circuitry is the SPF, may cause the single control circuitry to not operate to operate for Normal Clearing and, thus, must be properly simulated as a Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. A substantial treatment of the single control circuitry is made in the Technical Rationale, as well as specific discussion about Table 1 Planning Events P4 versus P5. Additional language about single and dual trip coils has been added to the Technical Rationale. Thank you, again, for your comments.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk. To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase "shall not be considered non-redundent" to "shall be considered redundant" at the end of the sentence for 13b, 13c, and 13d.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.	

Thank you, again, for your comments.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
We agree with the rational and contents of footnote 13 except for the exception for non-redundant communication equipment that is monitored and alarmed in 13b. Our concern with this exception is that teleprotection equipment that is part of a communication system may be in a failed state and not always generate an alarm.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT agrees with the respondent that a single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing that is not monitored and reported at a Control Center should not be considered redundant. Thank you, again, for your comments.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

The SPP Standards Review Group (SSRG) recommends the Standards Drafting Team (SDT) provide clarity on the statement "for Normal Clearing". NERC defines "Normal Clearing" as a situation where "[a] protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems."

If a communications system associated with protective functions is installed to provide faster tripping than required, does this fall into the "Normal Clearing" definition? If so, the installed communications system associated with protective functions to clear faults faster than necessary is a single point of failure.

The SSRG recommends the SDT consider adding language to the technical rationale document that explains the inclusion of the communication system associated with protective functions as a single point of failure.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the usage of "comparable" in Footnote 13 offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System. Additionally, the SDT intent in using comparable in Footnote 13 is explained in the Technical Rationale. The SDT has added a clarification section to the Technical Rationale to clarify the concept of comparable Normal Clearing, using an example of high-speed piloting along with a primary relay.

Thank you, again, for your comments.

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb

Answer	No
Document Name	

Comment

No. Westar Energy and Kansas City Power & Light Co. suggest that in Footnote 13d, single lockout relays that are monitored and report to a Control Center should be afforded the same exception as single trip coils that are monitored and reported to a Control Center. Without the exception, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability. The companies offer the following revision: d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except **when either** a single trip coil **or a single lock out relay** is both monitored and reported at a Control Center shall not be considered non-redundant)

Likes 0	
Dislikes 0	

Response
The SDT appreciates your feedback. The SDT did struggle with the topic of giving similar monitoring and reporting exceptions to auxiliary and lockout relays. While relay monitoring (e.g., relay trouble indication) may be adequate to announce when a lockout or auxiliary relay may have failed, it is not clear that relay monitoring is sufficient for identifying all possible relay modes of failure that may lead to Delayed Fault Clearing. Additionally, the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report specifically included auxiliary relays and lockout relays as DC control circuitry protection system attribute, noting that these devices are generally unmonitored and may remain in a failed state undetected for an extended period. Further, auxiliary and lockout relay failures in certain Protection System designs can be much more detrimental, leading to significantly Delayed Fault Clearing, than expected for the failure of a trip coil. For these reasons, the SDT chose not to exclude monitored and reported auxiliary relays and lockout relays when considering the control circuitry as a non-redundant component of a Protection System. Thank you, again, for your comments.

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No

Document Name	
Comment	

American Transmission Company (ATC) has concerns about the application and consistency of terms used in Footnote 13 compared to those used in other standards and the NERC Glossary of Terms, specifically Delayed Clearing and Normal Clearing Times. Reliability Standard PRC-004 introduced the term "Composite Protection System," whose definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. A failure of a Protection System component is not a Misoperation if the performance of the Composite Protection System is correct. A slower than typical operation of a Composite Protection System is considered a Misoperation if the delay results in the operation of at least one other Element's Composite Protection System. Normal Clearing Time of a Composite Protection System in the context of this standard could be interpreted as the clearing time of the slower of the redundant systems, as long as this clearing time does not result in the operation of another Element's Composite Protection Systems and acceptable system performance for the scenarios outlined in Footnote 13. However, such guidance or interpretation is currently missing from the Standard or Technical Basis.

In addition, ATC has concerns regarding the application of Footnote 13. Specifically, although monitoring of communication equipment has the potential to reduce the exposure to risk of delayed tripping, it does not eliminate the risk. By not requiring the analysis of delayed clearing on lines lacking redundant communication in the Planning Horizon, ATC (and other companies) may not identify transmission lines that need redundant communication to maintain generator or system stability. During a communication failure event, real-time operations is required to study the impact of delayed clearing for SLG or three- phase faults and mitigate any issues. This particular real-time requirement is maintained in the recent draft standards under Project 2015-09 Establish and Communicate System Operation Limits. It is not clear why the planning study requirements do not align with the operation requirements and require advance study of the same concern. Furthermore, this exemption presents a real risk to the system reliability. The Footnote 13 language transfers identification of this reliability risk into the real-time environment, where the tools used to identify dynamic instability do not typically exist. Regardless of whether the event actually occurs, the proposed Footnote 13 language creates a gap in the standards and exposes registered Transmission Operators to potential non-compliance under TOP-001 (and TOP-002, if the communication failure condition continues into the next operating day) for having failed to identify a stability related SOL and then operated the system to that limit.

In the real-time environment, ATC must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, ATC must operate within all System Operating Limits (SOLs) for the topology that exists at that moment, which explicitly includes the status of Protection Systems. With the loss of communication for a particular path, delayed clearing could exist for a fault and the response of the system or nearby generation may not be stable. Real-time tools would not identify the instability, and ATC would not identify the SOL to which it should have been operating. Identification of these issues should occur in the System Planning domain, where it then can be passed through to the Transmission Operator in accordance with FAC-014. The

Planning environment has sufficient time to consider these scenarios to help ensure that the instability is corrected, whether that corrective action is a system reconfiguration or a new system or generator limitation for that condition.

There are additional opportunities to align terminology between PRC-005 and TPL-001 if the Standard Drafting Team continues with the use of a monitoring and alerting exemption. Some examples include "Control Center" versus "location where corrective action can be initiated" and "Open-Circuit" versus "battery continuity." Furthermore, the standard fails to address what is an acceptable monitoring period that could be used for non-redundancy or time in which corrective action would be required. Some devices are monitored in-real time, while others test less periodically, including once a day or monthly. Finally, the standard as currently written fails to address those systems that are part of non-battery-based systems.

The use of double negatives in Footnote 13 is confusing (e.g., not considered non-redundant). Consider modifying the wording of the P5 requirement to Fault plus failure of a component of a Composite Protection System which results in remote and/or delayed clearing. In this context, delayed clearing would be a delay beyond the slower of redundant systems as described above. The footnote could be simplified to state that components to be considered include protective relays, communication systems, DC supply, and control circuitry associated with the protective functions.

The redundancy of communication paths needs to be addressed. Consider the following clarification, “Communication systems are considered fully redundant if, for any single component failure such as power line carrier equipment, microwave tower, tone path, or OPGW, one communication system remains fully functional.”

ATC is concerned about the impact of mitigation of single station DC failures for stations without open circuit monitoring. Monitoring reduces the exposure to risk but cannot mitigate it. While monitoring and alerting systems are starting to become available within the industry, from ATC's perspective, they are not widely implemented. The result would be any BES facility without redundant DC supplies being tested for P5 bus section contingencies will result in delayed clearing. For the sites that fail this scenario, ATC would elect for redundant DC supplies due to future concerns about the true "redundancy" of monitored equipment. The result would likely mean building new control houses at significant cost due to space constraints at existing facilities.

Finally, it is unclear as to what the appropriate evidence would be to demonstrate compliance with Footnote 13. There is no indication of what evidence type would be required to demonstrate that entities have redundancy or monitoring. Verification of redundancy of control circuitry could drive assembly of a significant number of station drawings, inventories, and other pieces of evidentiary documentation to prove redundancy. This verification has the potential to be extremely burdensome for both the industry and audit staff.

Likes 0	

Dislikes 0	

Response

The SDT appreciates your feedback. The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT has added treatment of the comparable Normal Clearing times principle to the Technical Rationale.

The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT agrees with the respondent that a single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing that is not monitored and reported at a Control Center should not be considered redundant.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5, does not believe that somehow Footnote 13 transfers identification of reliability risks associated with non-redundant components of a Protection System to any other Reliability Standard.

The SDT considers that Footnote 13 is consistent with the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations.

The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.

Thank you, again, for your comments.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	2015_10_Comment_MH_1.docx
Comment	
See attached comments	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that Footnote 13d is consistent with the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations. The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT does not desire to isolate auxiliary or lockout relays separate from the control circuitry. Thank you, again, for your comments.	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.	

The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT asserts that consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance. The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5. Thank you, again, for your comments.

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Footnote 13 items “b”, “c”, and “d” contain the parenthetical language “(except […] that is both monitored and reported at a Control Center shall not be considered non-redundant)”. It can be argued that monitoring and reporting these quantities at a Control Center does not adequately address the potential failure of these systems when called upon to act. I.e., just because the monitoring and reporting at a Control Center indicates that these systems are functional does not necessarily mean that they will function properly when called upon. There should be no argument that redundancy in items “b”, “c”, and “d” is more reliable than SPFs that are monitored at a Control	

Center; however, Peak can accept the risk-based decision and justification that, as quoted in the rationale document, “components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.”	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed language of Footnote 13, which clarifies the scope of non-redundant components.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
The follwoing comments (1 through 5) are being submitted on behalf of the City Light SMEs: Yes - Footnote 13, specifically section a, provides a clear definition of non-redundant components of a protection system.	

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA believes that the clarifications are an improvement.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback.

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6

Answer	Yes
Document Name	

Comment

The contents of Footnote 13 now provide additional clarification of Requirement expectations as it relates to non-redundant Protection Systems. However, including this level of detail in planning assessments raises concerns:

1. Is consideration of the Protection System details even possible or practical given the state of available information and modelling tools?

2. Does the complexity of the resulting models and planning assessments create an increased opportunity for incorrect results?

3. Will it essentially create a new "design" standard that will lead to increased protection system redundancy for all transmission facilities regardless of the impact on BES reliability. 4. By considering the conditions for monitoring Protection System components (e.g. trip coil, DC Supply, etc.), there is an indirect impact on existing Requirements included in PRC-005, which also consider component monitoring when establishing maintenance periodicity.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT does believe the consideration prescribed by Footnote 13 is achievable, that incorrect simulations are an inherent risk of conducting assessments, that Footnote 13 does not prescribe any required redundancy, and no other Reliability Standard references Footnote 13.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	

Comment	
While ITC generally supports the current content of Footnote 13, we would suggest the following addition. Update Footnote 13d to exclude the wiring to and from the trip coil, in addition to a single trip coil when required for Normal Clearing where it is monitored and reported. Suggested update, "A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip coil and wiring that is both monitored and reported at a Control Center shall not be considered non-redundant)."	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the proposed Footnote 13 offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Midcontinent Independent System Operator, Inc. (MISO) and New York Independent System Operator, Inc. (NYISO) do not join the ISO/RTO Council Standards Review Committee's (SRC) response to this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	

Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 1	Con Ed - Consolidated Edison Co. of New York, 3, Yost Peter
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Chris Scanlon - Exelon - 1	
Answer	
Document Name	TPL-001-5 Footnote 13 Double Negative Comment 090718.docx
Comment	
The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
The NYISO agrees that the removal of Req. 1, Part 1.1.2 will still meet the objective of FERC Order No. 786. We do not agree with the changes to Req. 2, Parts 2.1.4 and 2.4.4. We believe the assessment should be performed for all contingencies listed in Table 1, since all such contingencies are studied in the Operations Horizon. Not including all Table 1 contingencies in Req. 2 introduces a gap between the Near-term Planning and Operations Horizon assessments, poetentilally leading to a reliability gap. Other proposed NERC Standards, such as FAC-011-3, FAC-014-2, and FAC-015-1 are proposed to, among other things, improve the coordination between Planning and Operations. The proposed revisions here seem contrary to that intent.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that making changes to the current draft based upon an unballoted draft standard could create inconsistencies given that the draft standard could change course. The current draft aligns with the previous version of TPL-001-4 Requirement R2, Part 2.1.3 for events to be considered for known planned outages.	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	

While the modifications to Requirements R2, Parts 1.1.2, 2.1.4 and 2.4.4 are acceptable, the concerns covered by the proposed Requirement R2, Parts 2.1.4 and 2.4.4 would be better addressed through a modification of IRO-017.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO

Answer	No
Document Name	

Comment

We find the new language difficult to interpret. We provide the following comments for consideration to make the requirements more succinct:

The language seems to indicate a new procedure, or an edit to an existing procedure is required. We do not think the requirement should stipulate a new or modification to a procedure. We suggest revising the requirement as follows (applicable to both 2.1.4 and 2.4.4):

When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages expected to produce more severe System impacts on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with outage coordination procedure(s) or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

Additionally, the following sentence could be removed from the requirement and added to the technical rationale: *Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1."* The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT reviewed and considered the language revisions and has decided that the current language meets the FERC directives and the SAR of this SDT.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We find the new language difficult to interpret, and possibly redundant. We provide the following suggestions for consideration to make the requirements more succinct. The documented outage coordination procedure or technical rationale should cover the rationale for outage selection. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known	

outage(s) shall be selected for assessment consistent with a

documented outage coordination procedure or technical rationale by

the Planning Coordinator or Transmission Planner. Known outage(s)

shall not be excluded solely based upon outage duration. The

assessment shall be performed for the P0 and P1 categories identified

in Table 1 with the System peak or Off-Peak conditions that the System

is expected to experience when the known outage(s) are planned. Past or current studies may

support the selection of known outage(s), if the study(s) has

comparable post-Contingency System conditions and configuration

such as those following P3 or P6 category events in Table 1.

Additionally –

The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 Outage Coordination, which purpose states "To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.

IRO-017 R4 states:

Each Planning Coordinator and Transmission Planner shall jointly develop solutions

with its respective Reliability Coordinator(s) for identified issues or conflicts with

planned outages in its Planning Assessment for the Near-Term Transmission Planning

Horizon. The intent and requirements of IRO-017-1 R4 and proposed TPL-001-5 R2 parts 2.1.4 / 2.4.4 seem to overlap, potentially causing confusion.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA does not agree with the proposed revision. These studies are already performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. If issues were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an operating guide. The operational cases have a more accurate near-term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take siginificant new effort and time to complete. Outages in the planning horizon should be studied by the TP, while those in the operations horizon should be studied by the TOP.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The current draft as written is to analyze the Near Term Planning Horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT also notes that studying these in the near term planning horizon could allow identification of projects prior to the operations horizon.	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

In our opinion, any known/planned outages of major equipment for maintenance or construction should be included in the appropriate models to be assessed for P0-P7 planning events. Therefore, Requirement 1, Part 1.1.2 needs to be retained except for the words “with a duration of at least six months”.

We propose alternative language to Part 1.1.2 as follows:

"Known outage(s) of generation or Transmission Facility (ies) scheduled in the Planning Horizon."

Modification to Part 1.1.2, as proposed above, would also allow the last bullet of Part 2.1.3 to remain as an option for a sensitivity study.

We disagree with the language proposed for new Part 2.1.4. We disagree with the phrase “selected known outages” (line 2) as we believe this is not the intent of the Commission to pick and choose which planned outages should be assessed. We disagree with the development of a "documented coordination procedure" (line 5) as Transmission Planners and Planning Coordinators do not coordinate outages. Instead, we believe that a documented methodology or collection process to obtain the outages scheduled in the Planning Horizon needs to be developed. We disagree that the proposed assessment shall be performed for only the P0 and P1 planning events (lines 8 and 9), as we do not believe these analyses are sufficient to identify areas for non-consequential load loss during times of maintenance outages. We believe that if the changes to Part 1.1.2 are included as proposed above, then much, if not all, of the proposed Part 2.1.4 can be eliminated, which would be an enhancement to the standard.

As the FERC expressed in paragraph 42 of its Order 786, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." In our opinion, the language included at the end of Part 2.1.4

(lines 13-16) regarding "Past or current studies may support the selection of known outage(s) …" continues to support the idea of developing hypothetical or speculative outages based on previous analysis of Table 1 Planning Events P1-P7. Clearly this does not meet the intent of the Commission to include only planned maintenance outages, and in our opinion goes well beyond the directive.

If Part 2.1.4 is to remain, we propose that the language be changed to something similar to the following:

"When known generator and transmission maintenance outages are planned in the Near-Term Planning Horizon, the impact of these maintenance outages shall be assessed. The known outages included in the models shall be supported with a documented outage collection methodology/procedure or technical rationale for inclusion developed by the Transmission Coordinator or Transmission Planner."

Our concerns for Part 2.1.4 also apply to Part 2.4.4. For the reasons stated above, we cannot support the changes proposed by the SDT to meet the FERC directive.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that the FERC directive states that outages with a duration of less than 6 months could have a greater impact than those longer than 6 months. The SDT also notes that it considered a bright line of less than 6 months however the SDT ultimately decided that any duration chosen wouldn't be appropriate for every registered entity. The current draft provides the flexibility to determine which known outages have an impact and to study those in the near term planning horizon.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

As indicated in the Applicability section of TPL-001, applicability of this requirement falls on the PC and the TP. It should be noted that the TP does not own transmission assets under the TP fuction registration. Holding a TP accountable for knowing outage status of equipment in a planning model is nonsenscial. The outage of transmission equipment is determined by those entities requesting the outage, where the burden of proof should fall on the applicable entities providing data for building models under MOD-032-1 and not the TP. As noted in R1, planning models "shall represent projected System conditions"; the TP does not have full visibility of these projected system conditions, but expects that data submitted for building of the planning models, in accordance with MOD-032-1, is as accurate as the system being projected in each of the respective planning models.

Additionally, the proposed TPL-001-5 Draft 4 language "These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration." Should be removed, since the TP does not own transmission assets.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT notes that it attempted to look at the applicability section of the standard and found that it was outside the scope of the SAR for this SDT.

Terry BIlke - Midcontinent ISO, Inc. - 2

Answer	No
Document Name	

Comment

Moving the requirement for Order No. 786 to Requirement 2 is fine. However, MISO does not agree with the characterization of planned maintenance with respect to the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making necessary system improvements. This is more fully described in the response to question 3 below.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6

Answer	No
Document Name	
Comment	
NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis. Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers the current draft is clear that those outages selected are only to be considered under P1 events and does not agree that these described events are extreme events.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA believes that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT decided to make no change to the current draft given that in the requirements mentioned in your comments for R3 and R4 respectively have references to the subrequirements the SDT added to cover both steady state and stability studies. The SDT also notes that the scope of the current SAR would not allow for the creation of another standard to address Long Range Outage Coordination.	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT also notes that studying these in the near term planning horizon could allow identification of projects prior to the operations horizon.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We maintain that Planning Assessments and Operations Planning shall be coordinated. As currently proposed, the TPL standard only requires P1 events to be simulated when assessing planned outages in the Near-Term Transmission Planning Horizon. However, this is inconsistent with existing standards FAC-011-3 R3 and FAC-014-2 R6, which require the Reliablity Co-ordinator (RC) also to consider multiple contingencies when assessing these outages. Therefore, at a minimum, when the Planning Co-ordinator is assessing planned outages occurring in the Near Term Transmission Planning Horizon, they should simulate the contingencies that the RC would simulate when assessing and approving these outages, otherwise operations is held to more stringent/conservative performance than planning. Moreover, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the coordination between planning and operations. The proposed FAC-011-4 R5 requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. Hence, in order to improve this coordination between planning and operations and to eliminate any potential reliability gaps between these plans, the IESO proposes that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 should require at least the same contingencies to be assessed as part of the Planning Assessment for outage conditions as the ones identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4.	

Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that if entities choose to run additional event types there is nothing in the current draft to preclude them from doing so. The SDT also notes that there is nothing in the current FERC directive that speaks to event types required to be run as part of this assessment. The current draft aligns with the previous version of TPL-001-4 R2.1.3 for events to be considered for known planned outages.

Scott Downey - Peak Reliability - 1

Answer	No
Document Name	

Comment

While the changes to Requirement R2 Parts 2.1.4 and 2.4.4 represent a significant improvement over the currently effective TPL-001-4, Peak has a concern related to the contingencies required for study for the outages considered in the Planning Assessment. The primary concern is the lack of continuity between planning and operations with regard to contingency analysis. Per these proposed requirements, P1 contingencies are the only contingency types required to be studied for the outage conditions. However, in the operations horizon several Transmission Operators (TOP) and Reliability Coordinators (RC) consider (and require reliable system performance for) contingencies more severe than single P1 contingencies, as specified in the RC's SOL Methodology for the Operations Horizon per FAC-011-3 Requirement R3.2, R3.3, and R3.3.1. These multiple contingencies might include certain P4, P5, or P7 multiple contingencies. If there are multiple contingencies that are required for assessment (and are required to meet performance criteria) in the operations horizon, then those same contingencies should be assessed for planned outages in the planning horizon. Excluding these contingencies from the Planning Assessments for the outage conditions creates a reliability gap between planning and operations. Under the existing language, the planner's assessment of the outages would only identify reliability problems associated with P1 contingencies, whereas, if the planners considered the same contingencies that are considered in operations, the reliability gap between planning and operations would be closed. Any identified reliability risks in the Planning Assessment would result in either rescheduling the outage or proposing solutions that could be passed on to operations. If multiple contingencies that are used in operations are not required for assessment in the planning horizon, then the outcome is an environment where operations is held to more stringent/conservative performance than planning. This presents increased reliability risks, it conflicts with good utility practice, and it detracts from the principle of "plan it like you intend to operate it, and operate it like you planned it."

Furthermore, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the continuity between planning and operations. These proposed standards were posted for the 45-day formal comment period on 8/24/2018. The proposed FAC-011-4 Requirement R5 and subparts requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. If this standard passes ballot, then continuity between planning and operations would be further improved if TPL-001-5 R2 Parts 2.1.4 and 2.2.4 would require these same contingencies to be assessed as part of the Planning Assessment for outage conditions. Accordingly, Peak suggests that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 require an assessment of not only P1 contingencies, but also the additional single contingencies and multiple contingencies identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4.

It is possible that these more severe contingencies are unable to meet the performance criteria in Table 1 of TPL-001. This can be addressed by relaxing the performance criteria for these contingencies during prior outage conditions, where the assessments would only require that these contingencies demonstrate that instability, Cascading, or uncontrolled separation does not occur. Such a requirement actually provides even more alignment between planning and operations, considering proposed FAC-011-4 Requirements R6 parts 6.3 and 6.4 which stipulate that the performance criteria for contingencies more severe than single P1 contingencies are that the system demonstrates that instability, Cascading, or uncontrolled separation does not occur.

Peak also has a concern with the language in TPL-001-5 R2 Parts 2.1.4 and 2.2.4 that states, "System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned." Peak believes that the "or" should be "and", thus requiring the outages to be assessed against both System peak conditions and against Off-Peak conditions. If the outages are not assessed against both System Peak and Off-Peak conditions, there is an increased risk that significant reliability issued could go undetected. Peak does not believe that the determination of using System Peak versus Off-Peak conditions for this analysis should rely on engineering judgement. Alternately, the System Peak and Off-Peak language could be removed and replaced with "the range of system conditions that the System is expected to experience during the outage."

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that if entities choose to run additional event types there is nothing in the current draft to preclude them from doing so. The SDT also notes that there is nothing in the current FERC directive that speaks to event types required to be run as part of this assessment. The current draft aligns with the previous version of TPL-001-4 R2.1.3 for events to be considered for known planned outages.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment

The proposed removal of the six month minimum duration threshold for modeling planned outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 Operational Planning Assessments. The IRO-017 standard establishes the outage coordination process within the operations planning horizon, which covers the period from day-ahead to one year out. The outage coordination process includes development and communication of outage schedules, evaluating impacts and developing operating plans to mitigate outage conflicts, or rescheduling outages when necessary in order to reduce the reliability impact of the critical outage. This process ensures a more accurate modeling of expected system conditions, including information on concurrent outages.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT would also note that it considers removing the 6 month duration threshold for outages does not unnecessarily duplicate the assessment of known outages conducted as part of the operations horizon outage coordination process. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The relocation and revisions to wording related to the identification and treatment of known outages in the Near-Term Planning Horizon appear to address both the FERC and industry issues and concerns.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	

Comment	
It clarifies the requirement	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Removing Requirement 1, Part 1.1.2 makes sense as the base models should reflect the longer-term state of the system and not scheduled outages or contingency events. The changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4 are logical and allow for knowledgeable, technical rationale to determine which scheduled outages need to be analyzed. Note: references to “Near-Term Planning Horizon” should be replaced with the defined term from the NERC Glossary of Terms - “Near-Term Transmission Planning Horizon”.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	

Comments: GTC agrees in principle with the changes to Requirement 2, Parts 2.1.4 and 2.4.4. However, we recommend the following format changes and minor content changes to clarify the requirements:

2.1.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.1.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.1.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.1.4.3 The assessment shall be performed for the P0 and P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

2.4.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.4.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.4.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.4.4.3 The assessment shall be performed for the P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

One additional comment is concerning the "documented outage coordination procedure or technical rationale" by which Planning entities determine the appropriate outages to be assessed. The SDT included the following statement in the technical rationale that accompanied this posting:

"The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes."

This is a reasonable assumption but it is important to note there is no requirement for operating entities to provide this type of information to planners for all planned outages. The method which an auditor would use to determine the adequacy of a planner's procedure/rationale is unclear, in instances where planning entities do not have access to operating plans as they are produced or changed

-

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
We propose the following alternative text for Part 2.1.4: "…for the P0 and P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." Similarily we proposed the following alternate text for Part 2.4.4: "…for the P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." The System peak or Off-Peak models will normally be suitable for the Part 2.1.4 and 2.4.4 requirements. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Yes for R1.1.2 removal. - The removal is just fine, because it streamlines or simplifies R1 objective, and the sub-requirement that pertain to inclusion of known outages to near-term planning horizon cases will be addressed on future requirement R2.1.4 (for steady state) and R2.4.4 (transient stability), anyway. Yes for R2.1.4 and R2.4.4. – The proposed requirement gives the TP the choice of selecting which known outages can be included in the assessment, which are primarily outages that may pose severe system impacts to the system only. These may prove to be helpful, because the focus of the study relies only on the selection and inclusion of known outages that may cause severe system impacts to the system.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
No comments	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	

Texas RE appreciates the Standards Drafting Team's (SDT) reconsideration of Requirement language to address the comments previously submitted by Texas RE. The changes to TPL-001-5 R2, Part 2.1.4 appear to address the circular issue of R1 pointing to R2 and R2 pointing to R1.

Texas RE still contends there should be a specific requirement for the Planning Coordinators and Transmission Planners to develop an outage coordination process with specific criteria. As currently drafted, Part 2.1.4 and Part 2.4.4 state known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure *or* (emphasis added) technical rationale by the Planning Coordinator or Transmission Planner. Texas RE's position is that a technical rationale is not sufficient and there is no Reliability Standard that requires Planning coordinators and Transmission Planners to develop an outage coordination procedure. IRO-017-1 R1 requires each Reliability Coordinator to develop, implement, and maintain an outage coordination process for generation and Transmission outages within its RC Area.

Texas RE previously submitted comments including proposed language to R1 that would require each Transmission Planner and Planning Coordinator to maintain System models that include known outages of generation or Transmission Facilities. Texas RE again recommends revising TPL-005 R1.1 as follows:

1.1 System models shall represent:

1.1.1. Existing Facilities;

1.1.2. Known outages(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1 Establishes a criteria, supported by a technical justification, for identifying significant known outages based on MW or facility ratings; and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT also notes that time was spent trying to derive criteria to help drive consistency, however given the differences in system topology and geographic areas there was not a one-size-fits-all approach available that would allow for all the registered entities to meet the FERC directive of including those outage that have impact for their regions.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	
Document Name	
Comment	
How does new 2.1.4 meet the SDT's belief stated in the Technical Rationale that there is an "implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon." What is the measurement of whether the Technical Rationale developed under 2.1.4 is acceptable – simply that is not based on duration of the outage? How does having a documented outage coordination procedure satisfy the need for performing TPL analysis? Most entities already have such a process that is totally unrelated to TPL analysis. While it may be implied, the documented outage coordination procedure does not explicitly state that any modeling or contingency analysis is required.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT notes that the Technical Rationale provides some examples on how criteria or rationale could be selected, but is not meant to be an all-encompassing list. The SDT notes that it attempted to look at the applicability section of the standard and found that it was outside the scope of the SAR for this SDT.	

3. ***Do you agree with the proposed revisions to TPL-001-4?***

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp does not agree with the proposed removal of Requirement 1, Part 1.1.2 and changes to Requirement 2, Parts 2.1.4 and 2.4.4 for the reasons stated in question 2 above. PacifiCorp agrees with all other proposed revisions to TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT would also note that it considers removing the 6 month duration threshold for outages does not unnecessarily duplicate the assessment of known outages conducted as part of the operations horizon outage coordination process. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Yes and no. See comments provided for questions 1 and 2.	

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that if entities choose to run additional event types there is nothing in the current draft to preclude them from doing so. The SDT also notes that there is nothing in the current FERC directive that speaks to event types required to be run as part of this assessment. The current draft aligns with the previous version of TPL-001-4 Requirement R2, Part 2.1.3 for events to be considered for known planned outages.

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

As stated in our response to Question #1, AEP remains concerned by the increased complexity of Footnote 13 driven by its excessive detail. The version of Table 1 that is currently in effect is clear in its intent and application, however, we believe that Footnote 13 as currently proposed actually *removes* the clarity that was once there.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. While the SDT recognizes that Footnote 13 has become more detailed as a result of the proposed revisions motivated by the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations, the SDT does not believe it has become unnecessarily complex. On the contrary, the SDT considers that the proposed revisions to Footnote 13 has brought increased attention to assessment concerns that pre-existed in TPL-001-4 and has clarified considerations about non-redundant components of a Protection System, while facilitating flexibility in addressing the non-redundant components of a Protection System reliability concerns.

The SDT appreciates the suggestion to propose a new NERC Glossary of Terms definition, but believe this is unnecessary given the existing definitions of Normal Clearing and Delayed Fault Clearing. To the point, the SDT considers that the "intentional delay" included in the Delayed Fault Clearing definition is both intentional and inherent to the design of backup protection. The SDT has added additional narrative to the Technical Rationale to clarify this topic.

The SDT has suggested potential approaches to addressing the challenges of coordinating considerations regarding non-redundant components of a Protection System between planning and protection personnel in the Technical Rationale.

Thank you, again, for your comments.

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

SDG&E agrees with all revisions to TPL-001-4 except those related to P5 planning events for non-redundant components of a Protection System identified in footnote 13.

Likes 0	
Dislikes 0	

Response

Pursuant to the response from FERC Order 754, NERC SAMS and SPCS conducted an assessment, confirmed the existence of a reliability risk associated with SPF in Protection Systems, and concluded that it was appropriate to recommend that TPL-001-4 be modified to address the SPF. The SDT modified Table 1, Footnote 13 to capture the SAMS/SPCS recommendations for Category P5 events.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We maintain that the Contingency event that represents a 3 ph fault plus a failure of a non-redundant component of a Protection System remains a reliability concern and reiterate that the SDT's alternatives offered in Draft #1 and Draft #3 would address it:

- Keep the 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events, but require a Corrective Action Plan when Cascading is identified.
- Move the 3 ph fault + SPF in Protection System event to Table 1 Steady State & Stability Performance Planning Events and create a new P8 category. The only System performance requirement that should apply to P8 is that Cascading shall not occur and a Corrective Action Plan should be required when Cascading is identified.

The existing evaluation (except to separate breaker failure from the SPF in Protection System event) brings us back to square one.

Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	

Response

The SDT's previously proposed treatments of the 3ph Fault with SPF as (1) an extreme event requiring a CAP or as (2) a P8 planning event were not supported by industry. Hence, the SDT proposed in the Standard that, "3phase fault on…with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing", replace and be treated in the same manner as, "3phase fault on…with…a relay failure resulting in Delayed Fault Clearing".

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	

Comment

In the Extreme Events portion of Table 1, the use of the NERC defined term "Normal Clearing" is not sufficiently clear or could be misapplied. A composite protection system can be made up of redundant systems with significantly different clearing times. Failure within a redundant composite protection system can be interpreted as "Normal Clearing" based on the NERC definition of a "Misoperation". Using this definition, "Normal Clearing" would occur without providing clearing fast enough to meet stability

requirements. Steady State and Stability Performance Extreme Events should be evaluated by simulating "worst case clearing time" of the composite protection system for the element(s) unless otherwise specified. The use of the term "Delayed Fault Clearing" in the Stability Items 2e through 2f of the Extreme Events portion of Table 1 could be interpreted differently based on the NERC definition of "Delayed Fault Clearing". The NERC definition of "Delayed Fault Clearing" seems to apply to failures of an entire composite protection system, whereas clearing occurs via breaker failure or some remote clearing after an intentional delay. Using this interpretation of the definition, the failure of a portion of a redundant system which results in a slower clearing time would not meet the definition of "Delayed Fault Clearing", but could still result in clearing that does not meet stability requirements. Stability Items 2e through 2f of the Extreme Events portion of Table 1 should be studied under conditions where failure of a non-redundant component results in "worst case clearing time" for the composite protection system of the element(s).	
Likes 0	
Dislikes 0	
Response	
The SDT did not change the use of "Normal Clearing", as applied to Table 1 Extreme Events, but feels that the NERC definition is adequate. As applied in the proposed Standard, the use of "Delayed Fault Clearing" conveys the intent that the fault should be assessed recognizing the delay in fault clearing resulting from the possible SPF of the non-redundant components of a Protection System as enumerated in Table 1 Footnote 13. In this standard, Footnote 13 describes the components to be considered in SPF, which could cause a failure of a Protection System to operate as intended.	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT also notes that studying these in the near term planning horizon could allow identification of projects prior to the operations horizon.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

For the same reasons stated in question 2. BPA considers that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.

Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The SDT decided to make no change to the current draft given that in the requirements mentioned in your comments for R3 and R4 respectively have references to the subrequirements the SDT added to cover both steady state and stability studies. The SDT also notes that the scope of the current SAR would not allow for the creation of another standard to address Long Range Outage Coordination.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No

Document Name	
Comment	
See comments for question 2.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the current approach allows the flexibility for the TPs and PCs to select those outages for consideration utilizing any and all inputs/criteria needed to perform the assessment. The SDT considers the current draft is clear that those outages selected are only to be considered under P1 events and does not agree that these described events are extreme events.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
MISO supported the changes previously proposed by the SDT to create the P8 contingency. Given that a Corrective Action Plan is needed to address instability or cascading resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, the best way to achieve this requirement is through the creation of a P8 contingency rather than extreme events. Therefore, MISO agrees with the proposed P8 event. MISO would also support expanding the P5 contingency definition to include both a phase-to-ground fault and a three-phase fault as well should the Standard Drafting Team prefer to expand the P5 contingency definition rather than establish a new P8 event. The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making	

necessary system improvements. Adequacy, reliability, robustness, and resilience include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single transmission facility has been removed from service for planned maintenance or other purposes. All transmission facilities require planned outages from time-to-time to facilitate maintenance and repair work that cannot be performed hot, to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility, or for other purposes. Therefore, the eventual occurrence of a future planned outage on a transmission facility is certain and "known", not "hypothetical", only the timing and duration of the future outage could be considered uncertain or "hypothetical". If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy, robustness and flexibility to accommodate maintenance requirements in general.

In FERC Order 786, the Commission indicated the following at PP 41:

"We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding." (emphasis added)

It is "known" that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the proper planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient robustness and resilience to accommodate the planned maintenance flexibility during off-peak periods that will be required regardless of whether or not such activity has been scheduled at the time the planning assessment is conducted.

While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and robustness to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate a planned outage (which is generally considered unacceptable) or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedules planned outages when they are needed without sacrificing reliability or load continuity.

A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This contingency definition, which would be applicable only for non-peak conditions where planned maintenance is normally performed, could be implemented as a P2.1 contingency, followed by system adjustments (but no load shed), followed by a P1 contingency. With this new contingency added, the system would be planned to accommodate the planned outage of any one system element (transmission or generation element) during off-peak periods while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. Use of the P2.1 contingency as the maintenance contingency ensures continuity of service to load for the maintenance outage, which aligns with how the system would be operated. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, robust, resilient, and reliable in the future.	
Likes 0	
Dislikes 0	
Response	
The SDT's previously proposed treatment of the 3ph Fault with SPF as a planning event that required a Corrective Action Plan was not supported by industry. Hence, the SDT proposed in the Standard that, "3phase fault…with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing", replace and be treated in the same manner as, "3phase fault on….with…a relay failure resulting in Delayed Fault Clearing". The standard does <u>not</u> require a Corrective Action Plan for the 3ph Fault with SPF or any other extreme event. The changes proposed in Requirment R2, Parts 2.1.4 and 2.4.4 are sufficient and broad enough to accomplish what is proposed in a manner that addresses the unique preferences of the commenter. The SDT does not agree with the broad assertions of the commenter, which do not seem to sufficiently or adequately recognize the diversity of how outages are and can be managed. The proposed alternatives are more complicated than necessary for industry-wide application, but may well provide a good basis for the commenter to develop their own suitable outage coordination procedures or Technical Rationale envisioned by this proposed standard.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
The standard should be revised to represent the true intent for this standard, which is to hold the PC and TP accountable for assessing the state of the transmission system under specific scenarios, determine deficiencies, and act to correct those deficiencies. Requirements outside of the control of the TP are not an effective tool to determine if the intent of those requirements has been met. The TP can only assume that transmission equipment outages that represent a future timeframe (year one or year two), have been submitted by the entity requesting the outage, and are correct.	
Likes 0	
Dislikes 0	
Response	
The comments actually support the appropriateness of the structure of the proposed Requirment R2, Parts 2.1.4 and 2.4.4, highlighting that outage coordination and planning practices vary greatly across the industry. Hence, the proposed Standard is structured to enable outage coordination procedures or Technical Rationale to be fashioned that result in the capture of only those known outages which it would be reasonable, meaningful, and appropriate for the TP/PC to study in the Near-Term Planning Assessment.	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
See proposed changes to Requirements 1 (Part 1.1.2) and 2 (Parts 2.1.4 and 2.4.4) above. Clarification in needed on 'Table-1 – Extreme Events Second Column Stability Item 2f'. This should be changed to 3-phase close-in fault on Transmission circuit with failure of a non-redundant component of a Protection System result in Delay Fault Clearing. The FERC Order 754 study only looked at close-in line and bus faults with remote clearing. For end of line 3-phase faults, fault detection is unlikely with a failure of a non-redundant battery due to in-feed effect. It is not possible to run a stability study with this indeterminate	

state. The requirement as written will require installation of redundant batteries or battery monitors at all BES substations. If this is the case corrective action plans may take years to complete. Given the low probability of a battery failure concurrent with a 3-phase end of line fault, was this the intent of the standard? Also, for end of line faults can credit be given for the chargers ability to trip?

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT notes that the FERC directive states that outages with a duration of less than 6 months could have a greater impact than those longer than 6 months. The SDT also notes that it considered a bright line of less than 6 months however the SDT ultimately decided that any duration chosen wouldn't be appropriate for every registered entity. The current draft provides the flexibility to determine which known outages have an impact and to study those in the near term planning horizon.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment

TVA believes that the proposed changes to Footnote 13d creates a significant cost impact for a very small probability event. TVA believes that the proposed changes to Requirement 2, Parts 2.1.4 and 2.4.4 would add no value and create siginificant new effort and time to duplicate operations studies.

Likes 0	
Dislikes 0	

Response

The types of single points of failure noted in Footnote 13d were factors in the actual events that raised the single point of failure concern and motivated the proposed SPF changes to the Standard.

The SDT agrees with the importance of not duplicating operations study and normal outage coordination processes. Hence, the proposed Standard is structured to enable outage coordination procedures or Technical Rationale to be fashioned that result in the capture of only those known outages which it would be reasonable, meaningful, and appropriate for the TP/PC to study in the Near-Term Planning Assessment.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
.Please see comments in question 1 and 2 above. *Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):* Requirement 4.1 states that "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1….." Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1. *Additional Comment for consideration, related to clarification of the Standard:* Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The SDT did not make material changes to Table 1 outside of the scope of the project SAR. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. Thank you again for your comments.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
NV Energy feels it is prudent to require a corrective action plan resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, and should therefore not be considered an extreme event, but rather a planning event. NV Energy did not agree with the changes previously proposed by the SDT to create a new P8 contingency, but would support expanding the P5 event to include a three phase fault or a L-G fault, or replacing the L-G fault type with a three phase fault.	
Likes 0	
Dislikes 0	

Response	
The SDT's previously proposed treatment of the 3ph Fault with SPF as a planning event that required a Corrective Action Plan was not supported by industry. Hence, the SDT proposed in the Standard that, "3phase fault…with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing", replace and be treated in the same manner as, "3phase fault on….with… a relay failure resulting in Delayed Fault Clearing".	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	

Please see comments in question 2 above regarding known outages.

The current title of the technical rationale document is misleading as it could be interpreted as the technical rationale for single points of failure only, instead of TPL-001-5 as a whole. We request that the title of the technical rationale be changed to "TPL-001-5 Technical Rationale."

The language in 2.1.5 should be modified to align with 2.4.5 as shown below:

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 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.

Additionally, per the SDT's response to the last round of comments submitted, please add language in the technical rationale to clarify on what is meant by the spare equipment strategy. For reference, below were the comments submitted –

Does "spare equipment strategy" mean the existence of at least a single spare for major transmission equipment that has a lead time of more than one year; and does Requirement 2.4.5 imply that the existence of such a spare would eliminate the need to assess the impact of the possible unavailability of such equipment on System performance? If so, then Requirement 2.4.5 should be written this way.

As currently written, Requirement 2.4.5 lacks clarity. Every reasonable "spare equipment strategy" for equipment with a lead time of one year or more could result in the unavailability of such equipment; it is a matter of probability. For example, an Entity with 100 large power

transformers could have a spare transformer strategy of maintaining one system spare. However, it is possible that two transformers could fail during time span of one year. With only one spare, the Entity would be exposed to operating the system for up to one year with one less transformer than designed. Even if the Entity has four (4) spares, it is still possible that five (5) transformers could fail during one year (albeit with much lower probability), which would leave the Entity similarly exposed. Greater clarity is required for Requirement 2.4.5, as is more criterion development.	
Likes 0	
Dislikes 0	
Response	
The Technical Rationale appropriately references "Project 2015-10 Single Points of Failure TPL-001". The SDT did not feel that additional changes to Requirment R2, Part 2.1.5 were warranted or consistent with the SAR. The Standard is not prescriptive regarding what constitutes a spare equipment strategy and supports the TP/PC using reasonable judgement to determine the sufficiency of their sparing strategy.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
No. Westar Energy and Kansas City Power & Light incorporate by reference their response to Question 1.	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback. Q1: The SDT appreciates your feedback. The SDT did struggle with the topic of giving similar monitoring and reporting exceptions to auxiliary and lockout relays. While relay monitoring (e.g., relay trouble indication) may be adequate to announce when a lockout or auxiliary relay may have failed, it is not clear that relay monitoring is sufficient for identifying all possible relay modes of failure that may lead to Delayed Fault Clearing. Additionally, the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report specifically included auxiliary relays and lockout relays as DC control circuitry protection system attribute, noting that these devices are generally unmonitored and may remain in a failed state undetected for an extended period. Further, auxiliary and lockout relay failures in certain Protection System designs can be much more detrimental, leading to significantly Delayed Fault Clearing, than expected for the failure of a trip coil. For these reasons, the SDT chose not to exclude monitored and reported auxiliary relays and lockout relays when considering the control circuitry as a non-redundant component of a Protection System. Thank you, again, for your comments.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The addition of new single point of failure of selected non-redundant Protection System Components to the P5 contingency event category seems appropriate. Elimination of the P8 contingency event category and moving the new single point of failure of selected non-redundant Protection System Components to the Extreme Events category seems appropriate. The language in Footnote 13 is still a concern, as noted in ATC's comments on Question 1 above.	
Likes 0	

Dislikes 0	

Response

Q1 Response: The SDT appreciates your feedback. The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT has added treatment of the comparable Normal Clearing times principle to the Technical Rationale.

The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT agrees with the respondent that a single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing that is not monitored and reported at a Control Center should not be considered redundant.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5, does not believe that somehow Footnote 13 transfers identification of reliability risks associated with non-redundant components of a Protection System to any other Reliability Standard.

The SDT considers that Footnote 13 is consistent with the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations.

The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.

Thank you, again, for your comments.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro

Answer	No
Document Name	
Comment	
See comments for question 1.	
Likes 0	
Dislikes 0	
Response	
Q1 Response: The SDT appreciates your feedback. The SDT considers that Footnote 13d is consistent with the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations. The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. The SDT does not desire to isolate auxiliary or lockout relays separate from the control circuitry.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the proposed revisions as drafted.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes

Document Name	
Comment	
Seattle City Light agrees with the proposed revisions to the TPL-001-4. The definition of the non-redundant components of protection system is also adequate and provides clarity to the definition of non-redundant components of protection system.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
We agree with the proposed revisions except as noted on this Comment Form.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
We agree with the proposed revisions except as noted on this Comment Form.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC thanks the SDT for their work on developing this revision to the TPL-001 and agrees with the work they have done so far. ITC does not believe though that the language for the Requirements 3.5 and 4.5 for the evaluation of the non-redundant component of a protection scheme goes far enough. While it does require industry to evaluate the consequences of the configurations, it does not require a Corrective Action Plan be developed for any significant affect to the transmission system. ITC believes a CAP should be required.	

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT's previously proposed treatment of the 3ph Fault with SPF as a planning event that required a Corrective Action Plan was not supported by industry. Hence, the SDT proposed in the Standard that, "3phase fault…with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing", replace and be treated in the same manner as, "3phase fault on….with… a relay failure resulting in Delayed Fault Clearing".

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group

Answer	Yes
Document Name	

Comment

Studying the steady-state and dynamic impacts of events involving the non-operation of single elements of a Protection System as well as notable scheduled outages is worthwhile in order to maintain transmission system reliability.

Likes 0	
Dislikes 0	

Response

The SDT appreciated your feedback.

Glenn Barry - Los Angeles Department of Water and Power - 5

Answer	Yes
Document Name	

Comment

It is appropriate

Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.

The SDT intent has been described extensively in the Technical Rational. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT asserts that consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Please see Texas RE's response to #2.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	

4. *Do you agree with the proposed implementation plan?*

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The first timeframe following FERC's approval of TPL-001-5 needs to be 5 years, rather than 3 years, to perform all the required tasks (e.g., make model changes; develop the new Footnote 13 contingencies; perform the new known outage, long lead time, P5, and Extreme event analyses; and develop CAPs for non-P5 contingency system deficiencies). The timeframes of 2 years and 4 years to complete the other required tasks seem acceptable.	
Likes 0	
Dislikes 0	
Response	
Thank you very much for your comments. SDT appreciates it. However, SDT considers that 3 years is adequate time for the first assessment to be completed without CAPS. There is an additional 2 years allowed to developed CAPS which provides a total of 5 years for assessment and CAPS together.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SSRG notes that after the 48-month implementation sunset provision has expired, the implementation plan will not provide an entity with sufficient time to implement a Corrective Action Plan (CAP) identified in future annual planning cycles.	

For example, a CAP that identifies a facility that will require longer than one year to construct will not be in-service by the next annual planning cycle, which will impact the Planning Coordinator's (PC) the ability to meet the Table 1 performance requirements for the next annual planning assessment. In other words, an unintended and unavoidable consequence of the requirement may be a violation of R2.7 through no fault of the PC performing the annual study and preparing the CAP.

A solution to the issue would be to include an exception in Section 2.7.3 or create a new Section 7.2.4 that alleviates the need to meet the Table 1 performance metrics for subsequent planning assessments when P5 events identify a capital project as a CAP and no other mitigation can be achieved. The exception would be extended until the capital project can be placed into operation.

Likes 0	
Dislikes 0	

Response

Thank you very much for your comments. SDT appreciates it. The SDT did consider employing an open-ended approach to when entities must comply with the portion of Requirement R2, Part 2.7 that states: "the planned System shall continue to meet the performance requirements in Table 1" for CAPs developed to address failures to meet System performance requirements of the Table 1 Planning Event P5. However, the SDT determined that having an indefinite period before fully enforcing the proposed TPL-001-5 was unacceptable. The SDT has proposed an implementation plan that is of significant duration which is intended to give applicable entities sufficient time to modify appropriate processes as necessary to prepare for analytical changes affected by the modifications to the Table 1 Planning Event P5 and Footnote 13. Additionally, the SDT recognizes that unforeseen circumstances may inevitably affect an entity's ability to achieve the actions or timetable specified in a Corrective Action Plan, but this is a reality present in the existing TPL Reliability Standard and is not fundamentally different with regards to the proposed TPL-001-5. Therefore, the SDT decided not to make any changes to the implementation plan.

Glenn Barry - Los Angeles Department of Water and Power - 5

Answer	No
Document Name	

Comment

Depending on the different mitigations, it may take longer to implement.

Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback. However, an open ended implementation date does not meet the intent of the reliability standards. SDT considers that 9 years is adequate time to fully meet the standard.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. However, SDT considers that 3 years is adequate time for the first assessment to be completed without CAPS. There is an additional 2 years allowed to developed CAPS which provides a total of 5 years for assessment and CAPS together.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. However, SDT considers that 3 years is adequate time for the first assessment to be completed without CAPS. There is an additional 2 years allowed to developed CAPS which provides a total of 5 years for assessment and CAPS together.	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	
• PJM planning procedures do not allow for redispatch to address reliability criteria violations. Based on this, PJM has some concerns regarding requirements to fully implement Corrective Action Plans in accordance with the identified schedule. As the RTO, PJM does not have control over the construction schedule, and relies on individual Transmission Owner to complete construction and implement enhancements by the required in service date detailed in the Corrective Action Plan. • The sentence "The first annual Planning Assessment shall be completed in accordance with TPL-001-5, but without CAPSs for revised P5, by this date." in Figure 1 of the Implementation Plan could use some clarification. PJM in concerned that the sentence implies that revised P5 events, while not requiring a CAP, still need to be included in the Planning Assessment at the t+36 Point on the timeline. PJM Proposes the following revisions to clarify that revised P5 events are not required for inclusion in the assessment during this first 36 month period: “The first annual Planning Assessment (excluding revised p5 events), shall be completed in accordance with TPL-001-5, but without CAPs for revised p5, by this date.”	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT disagrees and considers the implementation plan is clear as written.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy does not support the proposed Implementation Plan. Without knowing at this time the potential size and scope of the work that will be necessary for implementing the CAPs, we cannot agree on the 48 month portion of the Implementation Plan. These corrective actions will likely involve improvements to protection systems for BES elements and these require system outages to critical lines that are only made available during low-load periods that will extend the overall time required to complete the CAP. We disagree with assigning an implementation period to an unknown scope of work. We suggest the SDT consider a flexible Implementation Plan with phases that can be assessed depending on the size and scope of work.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. However, SDT considers 48 months adequate time to develop CAPs. Please refer to the Implementation Language that states, "Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d."

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. Thank you very much for your comments. SDT appreciates it. However, SDT considers that 3 years is adequate time for the first assessment to be completed without CAPS. There is an additional 2 years allowed to developed CAPS which provides a total of 5 years for assessment and CAPS together.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Since we have concerns with some proposed revisions, (please see comments in question 1 and 2 above) we feel it is premature to consider a specific implementation plan.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
While the implementation timelines to study and develop CAPs are reasonable, TVA does not agree with the implementation timeline for completing CAPs to address the modified P5 events. These changes will require extensive work in order to make protection systems completely redundant for these events, requiring switch houses in some cases. If several switch houses are required, the proposed implementation plan would not provide adequate time to coordinate extensive outages and complete the corrective action plans.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. However, SDT considers 48 months adequate time to comply with the bolded part of Requirement R2, Part 2.7 that states: "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" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d."	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
We do not agree with the proposed edits or non-TP related requirements, hence we do not agree with the proposed implementation plan, at this time.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We believe the changes recommended above need to be made before we agree with an implementation plan.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback.	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
More time is needed to implement the proposed changes.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. However, SDT believes that 9 years total implementation period is adequate time to fully meet the standard.	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	

Answer	No
Document Name	
Comment	
As we have mentioned before, SDG&E does not agree with the changes related to P5 planning events for non-redundant components of a Protection System identified in footnote 13. Unfortunately, a great deal of the changes to the implementation plan are to allow time for the Transmission Planners to coordinate with protection engineers on addressing these new requirements.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. However, SDT believes that 9 years total implementation period is adequate time to fully meet the standard.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
We believe that the proposed implementation plan is reasonable. A significant amount of protection and controls related data and design drawings will have to be accessed and reviewed in order to facilitate the ability to study the required additional dynamic simulations.	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SCL agrees with the implementation plan and the timeline given to accomplish the plan.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The implementation plan profides sufficient time to perform studies and coordinate CAPs with external entities to meet compliance with TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	
The legal framework in Manitoba Hydro's jurisdiction does not permit the use of an implementation plan. The proposed NERC 9-year implementation plan appears reasonable.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	
Comment	

Texas RE appreciates the SDT's attempt to clarify the implementation plan and the timeline provided is helpful. Texas RE recommends explicitly saying which requirements are applicable in the Compliance Date and Initial Performance date sections. Based on the words written (not on the visual timeline), Texas RE understands the IP as follows:

- First calendar quarter 36 months following regulatory approval.
    - The effective date of the standard is the first day of the first calendar quarter 36 months following the effective date of the applicable governmental authorities order approving the standard. This date serves as a starting point for the implementation plan.
    - In accordance with the Initial Performance section, applicable entities must complete the planning assessment without CAPs by the effective date of the standard, or 36 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes there is no requirement mentioned. **In the interest of clarity and not being vague Texas RE strongly recommends the implementation plan specify which requirement this date refers to.**
    - 60 months following regulatory approval.
        - In accordance with the Initial Performance section, applicable entities must develop any required CAPs 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 b, c, and d, or 36 months plus 24 months, or 60 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes this is also indicated in the Compliance Date section, **which is redundant and could cause confusion**.
    - 108 months following regulatory approval
        - In accordance with the Compliance Date section, for CAPs developed to address failures to meet Table 1 performance requirements for the p5 planning event for the non-redundant components of a Protection System

	identified in footnote 13 items a, b, c, and d, or 36 plus 72, or 108 months following the effective date of the applicable governmental authority's order approving the standard.
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT has created an implementation plan that is clear regarding the effective date of the proposed TPL-001-5 as well as the compliance dates of each of the modified requirements. Because the standard involves the performance of periodic requirements the implementation plan includes the dates by which entities must perform those requirements for the first time. The implementation plan was crafted in conjunction with NERC staff and according to NERC guidelines intended to standardize implementation across all future Reliability Standards.	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	
Document Name	
Comment	
LES supports the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

5. ***Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?***

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	

PacifiCorp believes that the proposed revisions to TPL-001-4 to model known outages with a duration of less than six months in the annual Planning Assessment are not a cost effective way of meeting FERC directives in Order No. 786 as these studies are already being performed in TOP-003 and IRO-017 Operational Planning Assessments.

PacifiCorp agrees that the proposed revisions to TPL-001-4 along with the Implementation Plan are a cost effective way of meeting FERC directives in Order No. 754 addressing reliability issues associated with single points of failure in protection systems.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT would also note that it considers removing the 6 month duration threshold for outages does not unnecessarily duplicate the assessment of known outages conducted as part of the operations horizon outage coordination process. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.

Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No

Document Name	
Comment	
See question 2	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT. The SDT also notes that studying these in the near term planning horizon could allow identification of projects prior to the operations horizon.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the revision to the standard and the implementation plan do not adequately address industry concerns about the costs needed to plan and construct a project for a planned maintenance outage of short duration. Those planned maintenance outages will be coordinated ahead of time according to outage planning processes. It is not cost effective to plan and construct a project for a planned maintenance outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes. Requiring a low-probability, single-point-of-failure of protection systems to be analyzed as a Planning Event is beyond prudent planning. The proposed changes could be a very-significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System.	

The proposed changes to the standard would require industry to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP or PC to decide whether mitigating possible Cascading is cost effective. The cost effectiveness document falls short of providing any substantive cost effectiveness analysis and is more like a repeat of the proposed changes to the requirements & footnote 13.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT has proposed the current language in Requirment R2, Part 2.1.4 to address the concerns raised in FERC Order 786 that specifically states that a 6 month threshold could exclude maintenance outages of significant threshold. The SDT have included language that allows for the greater flexibility both in selecting outages and in modeling across the continent while meeting the FERC directive 786 based on industry comments. FERC Order 754 requires the consideration of P5 events based Section 1600 Data Request. A delineation has been created between P5 events and three phase faults which are considered an extreme event. The goal of the SDT was to ensure that cost effectiveness was considered and that different options were talked over. The SDT discussed at length different options and scenarios, and that the proposed draft and implementation plan meets the FERC directives and the SAR of this SDT.	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Since the standard does not meet the objective of Order No. 754, the question of whether or not it is cost effective is moot.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates your feedback. The SDT has addressed the objectives of Order 754 as defined in the SAR while gaining industry approval.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
FERC directives, cost effective or not, are a direct order of action which in accordance with the directive, if the directives determine that transmission system deficiencies exist being detrimental to state of the transmission system, those deficiencies should be acted on and corrected. Allowing more time (+12 months to all milestones) for the implementation as a result of these changes, may minimize the financial impact.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT considers that the proposed implementation plan meets the FERC directives and the SAR of this SDT.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA does not believe the proposed changes to Footnote 13d are a cost effective approach. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. The SDT considers that Footnote 13d is consistent with the SPCS/SAMS “Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request” report recommendations. The SDT considers that the probability of failure for a non-redundant component of a Protection System should not be confused with the severity of failure to meet System performance requirements of Table 1. The SDT has emphasized in the Technical Rationale that Footnote 13 directs which non-redundant components of a Protection System should be considered when simulating the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Footnote 13 does not prescribe a level of redundancy for the System, nor does it prescribe Corrective Action Plans for non-redundancy. To the point: the Table 1 Planning Event P5 prescribes the required System performance given failure of a non-redundant components of a Protection System. The SDT considers that the proposed Footnote 13d offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5.	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
While the proposed revisions to TPL-001-4 along with the Implementation Plan may be a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754 in terms of corrective action plans, the proposed revisions will present a very significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System. This incremental burden will have adverse cost impacts.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. the SDT understands the significant work that would be required to investigate and consider “non-redundant” components of a Protective System and has allowed significant lead time to complete the work as outlined in the implementation plan. Industry stakeholders have commented on both the standard and implementation plan.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System.

It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.

Likes 0	
Dislikes 0	

Response

The SDT appreciates your feedback. The SDT intent has been described extensively in the Technical Rationale. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT asserts that consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

The SDT has revised Footnote 13 to be explicit about what non-redundant components of a Protection System shall be considered; the SDT disagrees that it is necessary to specify equipment that need not be considered in Footnote 13. The equipment omitted from Footnote 13 consideration is described in the Technical Rationale. Additionally, revisions to the Technical Rationale to address items such as reclosing circuitry and trip coils have been affected.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5.

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
The proposed addition of "non-redundant" components of a Protection System, in particular Footnotes 13.b. and 13.d., to this Standard may add significant resource and financial burden to Transmission Owners (TOs) that in all cases may not provide a benefit to BES reliability. Although a planning standard, the Requirements as proposed may indirectly result in TOs expanding internal "design" standards to implement redundant Protection Systems on all transmission facilities regardless of the impact on BES reliability. As an alternative approach, the SDT could consider addressing the FERC directives by expecting planning assessments be performed with the assumption that all Protection Systems are non-redundant, and then when concerns are identified, the entity would confirm that there is a redundant Protection System in place or develop a CAP to address the non-redundant Protection System. Other than increasing the scope of the planning assessments, this type of process to investigate concerns as they are identified, might eliminate the initial administrative burden on collecting detailed Protection System information and building models with sufficient detail and accuracy. It would also avoid the unintended consequence of TOs upgrading all transmission facilities with non-redundant Protection Systems, regardless of the impact on BES reliability.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. the SDT understands the significant work that would be required to investigate and consider "non-redundant" components of a Protective System and has allowed significant lead time to complete the work as outlined in the	

implementation plan. Industry stakeholders have commented on both the standard and implementation plan. The SDT has not prescribed how an entity is to perform its studies. This is left up to each entity to determine.	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. Please refer to the SDT response to MRO NSRF.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. Please refer to the SDT response to MRO NSRF.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No

Document Name	
Comment	
ITC does not believe it is cost effective to study the consquences of non-redundant protection devices and not require a CAP for these scenarios should their affect on the transmission system be significant and detrimental. ITC believes if the results of a study of these types of events show this, a CAP should be required.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. the SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protective System and has allowed significant lead time to complete the work as outlined in the implementation plan. Industry stakeholders have commented on both the standard and implementation plan.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
It is not clear whether this will be cost effective at this point.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	

Comment	
While the modifications to requirements R1.1.2, R2.1.4 and R2.4.4 are acceptable, the concerns covered by the proposed requirements R2.1.4 and R2.4.4 would be better addressed through a modification of IRO-017.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The current draft as written is to analyze the near term planning horizon known outages. The SDT agrees that the addition is to help the coordination between IRO-017 and TPL-001. The SDT notes that changes to IRO-017 were considered as an alternate solution however changes to standards outside of TPL-001 were outside the scope of the SAR the team was provided. The SDT considers that the current approach meets the FERC directives and the SAR of this SDT.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	No
Document Name	
Comment	
No. Westar Energy and Kansas City Power & Light’s incorporate by reference their response to Question 1. Without the exception offered in response to Question 1, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability.	
Likes 0	
Dislikes 0	

Response	
The SDT appreciates your feedback. The SDT understands the significant work that would be required to investigate and consider “non-redundant” components of a Protective System and has allowed significant lead time to complete the work as outlined in the implementation plan. Industry stakeholders have commented on both the standard and implementation plan.	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC has concerns about that current Implementation Plan and cost-effectiveness of the proposed revisions to TPL-001-4. The current proposed language for Footnote 13 leaves uncertainty in applicability and potential gaps in studies through the use of exemptions, as noted in ATC’s comments on Question 1 above. Furthermore, the uncertainty in the amount evidence to prove redundancy and/or monitoring has the potential to be a significant work effort. Regarding studies that are to be performed, the proposed TPL-001-5 standard and Implementation Plan are cost-effective, with the exception being the first 3-year timeframe of the Implementation Plan, as noted in ATC’s comments on Question 4 above.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT has added treatment of the comparable Normal Clearing times principle to the Technical Rationale. The SDT considers that the proposed Footnote 13b offers applicable entities sufficient flexibility when considering non-redundant components of a Protection System for simulation as the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h.	

The SDT agrees with the respondent that a single communications system associated with protective functions necessary for correct operation of a communication-aided protection scheme required for Normal Clearing that is not monitored and reported at a Control Center should not be considered redundant.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5, does not believe that somehow Footnote 13 transfers identification of reliability risks associated with non-redundant components of a Protection System to any other Reliability Standard.

The SDT considers that Footnote 13 is consistent with the SPCS/SAMS "Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" report recommendations.

The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	

The proposed revision and 9-year implementation plan may be a reasonable way of meeting the FERC directive. However, MH feels that the analysis and mitigation of 115 kV and 138 kV stations is burdensome and likely expensive without necessarily improving overall BES reliability. As a result, we propose the following:

1. Implementing a risk based assessment to identify critical facilities of concern rather than making full protection redundancy a bright line requirement for all BES facilities.
2. For P5 definition of HV limit should be considered from 200 to 299kV.

GENERAL COMMENT

MH will be unable to adopt this standard as a NERC standard based on legislative restrictions in Manitoba. However, changes proposed in TPL-001-5 that are acceptable to MH would be adopted in a future Manitoba standard, MH-TPL-001-5.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback. The standard and P5 in particular will be applicable to the BES as directed by the FERC directive.	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	

Q1 Response: The SDT appreciates your feedback. The SDT agrees with the awkwardness of the Footnote 13 subpart language and has revised it to be more clear.

The SDT intent has been described extensively in the Technical Rationale. In summary, the SDT disagrees that backup protection is redundant to a Protection System designed for Normal Clearing. Moreover, by NERC Glossary of Terms definition, Delayed Fault Clearing is that which is associated with correct operation of a breaker failure protection system or backup protection. The SDT has emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The SDT asserts that consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

The SDT disagrees that the single communication system exemption when a system is monitored and reported to a Control Center somehow exposes operating entities, such as a Transmission Operator, to any compliance risk. The SDT has emphasized that the

consideration of non-redundant components of a Protection System, including acceptable exclusions, simply affect the manner by which Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h are simulated. The SDT does not know of any other Reliability Standard that references Footnote 13 other than TPL-001-5. Thank you, again, for your comments.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner.	
Likes 0	

Dislikes 0	
Response	
The SDT appreciates your feedback.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
It meets both FERC directives. Whether it's cost effective or not remains to be seen.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
OKGE supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SSRG supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
We believe that meeting FERC Order 786 has nothing to do with cost effectiveness. While we agree with the concept of requiring redundant system protection elements only where they are needed, per Order 754, the process of having system protection engineers	

perform analysis for each BES facility to determine clearing times for failures of non-redundant system protection elements is burdensome and will require significant additional man-hours.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No comment of opinion on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	
Comment	
Section 2.1.4 – Capitalize “c” in Planning coordinator Section 2.4.5 – delete “Based upon this assessment” at the beginning of the second sentence to be consistent with R2.1.5	

Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
The SDT appreciates your feedback.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

Additional comments received from Mike Smith - Manitoba Hydro (via attachment link in the comment report)

MH recommends the following changes to the footnote 13 of Table 1 (new text in red, removed text in green strikeout).

b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communications system that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant);

c. A single station dc supply and it's DC distribution circuits associated with protective functions required for Normal Clearing (except a single station dc supply and it's DC distribution circuits that is both monitored and reported at a Control Center for both low voltage and open circuit shall ~~not~~ be considered ~~non-~~redundant);

d. A single ~~control~~ trip circuitry ~~(including auxiliary relays and lockout relays)~~ associated with protective functions, from the ~~dc supply~~ protection relay through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip circuit and coil that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant).

e. A single auxiliary tripping or lockout relay associated with protection tripping;

Rationale:

In footnote-13c, it is not clear whether or not monitoring is a satisfactory way to address only the SPF of the main supply (batteries and main bus) or also of the various branch circuits involved in DC distribution. The proposed changes allow for monitoring exceptions for DC Distribution and components of the trip circuit which are low probability items for failure similar to the previous exceptions permitted for DC supplies, communications and trip coils. We would also like to propose to put auxiliary trip relays and lockout relays on their own line to make it 100% clear that they must be considered in a SPF analysis.

Comments received from Jeremy Voll - Basin Electric Power Cooperative (via attachment link in the comment report)

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

☐ Yes
☒ No

Comments: Please consider the following:

Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, "shall be considered redundant".

Add wording like, "Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance." at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the "Clarification: Is backup clearing redundant?" section on page 3 of the Technical Rationale with a different question and discussion like the following:

Clarification: "When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?"

If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one ofthese protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- "Voltage and current sensing devices of a Protection System are not considered." Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- "Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant". Discussion of this matter is only in the Technical Rationale (p. 5) right now
- "The reclosing relays of a Protection System are not considered." This matter is not presently discussed in the Technical Rationale.
- "Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant." This matter is not presently discussed in the Technical Rationale.
- "Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant." This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

☒ Yes
☐ No

Comments:

The revisions appear to address both the FERC and industry issues and concerns. Do you agree with the proposed revisions to TPL-001-4?

☒ Yes
☐ No

Comments:

3. Do you agree with the proposed implementation plan?

☐ Yes
☒ No

Comments:

It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.

4. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost-effective way of meeting the FERC directives in Order No. 754 and Order No. 786?

☐ Yes
☒ No

Comments:

See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System.

It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.

Comments received from Chris Scanlon – Exelon (via attachment link in the comment report)

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

☐ Yes
☒ No

Comments: For clarity of purpose the double-negatives should be removed from 13b, 13c, and 13d. Consider: "…*that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant)*"

End of report

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 fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee authorized Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal comment period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017
45-day formal comment period with additional ballot	February 23 – April 23, 2018
45-day formal comment period with additional ballot	July 30 – September 14, 2018

Anticipated Actions	Date
10-day final ballot	October 2018
Board adoption	November 2018

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

   - Planning Coordinator.
   - 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 MOD-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. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

1.1.5. 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 its 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. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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. Based upon this assessment, an 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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 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.

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. 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.

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.

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>
<tr><th rowspan="2">R #</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td>R1.</td><td>The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.</td><td>The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.</td><td>The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.</td><td>The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5.
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 standard 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,</td><td>The responsible entity failed to comply with two or more of the following Parts of</td></tr>
</table>

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
			Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	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.
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.	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.	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.	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 to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
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.	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 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 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 The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	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 The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11] b. Loss of all Transmission lines on a common Right-of-Way[11]. 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[10] resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing. e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

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 fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee authorized Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal comment period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017
45-day formal comment period with additional ballot	February 23 – April 23, 2018
45-day formal comment period with additional ballot	July 30 – September 14, 2018

Anticipated Actions	Date
10-day final ballot	October 2018
Board adoption	November 2018

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-~~4~~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

   - Planning Coordinator.
   - Transmission Planner.

5. **Effective Date:** **See Implementation Plan.**~~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~~
- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

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~~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) with a duration of at least six months.~~

~~**1.1.3.**~~**1.1.2.** New planned Facilities and changes to existing Facilities.

~~**1.1.4.**~~**1.1.3.** Real and reactive Load forecasts.

~~**1.1.5.**~~**1.1.4.** Known commitments for Firm Transmission Service and Interchange.

~~**1.1.6.**~~**1.1.5.** 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~~ its respective area, using data consistent with MOD-~~010 and MOD-012~~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.**~~**2.1.3.** 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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 ~~studied~~assessed. Based upon this assessment, an~~The studies~~ 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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 ~~&~~and 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~~ 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. 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.

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.~~6~~5. 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~~032 standard~~s~~ and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				The responsible entity does not have a completed annual Planning Assessment.
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.	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.	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.	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 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.
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.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements	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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

~~B.~~D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	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 has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees.	

Version	Date	Action	Change Tracking
		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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay[13]~~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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   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[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~e.~~i. 3Ø internal breaker fault. ~~f.~~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. ~~Applies~~For purposes of this standard, non-redundant components of a Protection System to ~~the following~~consider are as follows: a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions~~ or types: pilot (#85), distance (#21), differential (#87), current (#50, 51,~~, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and ~~67),~~reported at a Control Center); c. A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage ~~(#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~and open circuit); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

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.

~~C. Measures~~

~~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, 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.~~

~~M2.~~M1. ~~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.~~

~~M3.~~M1. ~~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.~~

~~M4.~~M1. ~~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.~~

~~M5.~~M1. ~~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.~~

~~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.~~

~~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.~~

~~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.~~

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 fourth draft of the proposed standard.

Completed Actions	Date
Standards Committee authorized Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal comment period	April 25 – May 24, 2017
45-day formal comment period with initial ballot	September 8 – October 23, 2017
45-day formal comment period with additional ballot	February 23 – April 23, 2018
45-day formal comment period with additional ballot	July 30 – September 14, 2018

Anticipated Actions	Date
10-day final ballot	October 2018
Board adoption	November 2018

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 MOD-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. New planned Facilities and changes to existing Facilities.

1.1.3. Real and reactive Load forecasts.

1.1.4. Known commitments for Firm Transmission Service and Interchange.

1.1.5. 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 its 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. 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.

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning C~~c~~oordinator or Transmission Planner~~s~~’s portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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. Based upon this assessment, an~~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, Part2.6. 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. 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.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

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, Part2.6 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 2.1.3 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 Schemes.
- 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. 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.

3.3. Contingency analyses for Requirement R3, Parts 3.1 and 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.

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. 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.

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

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

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.5.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.5. 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 standard~~s~~ and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	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.	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.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
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.	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.	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.	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 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.
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.	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	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	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

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
		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.	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
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.
R8	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

D. Regional Variances

None.

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to "0.1"	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote 'b' pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	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.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR	

Version	Date	Action	Change Tracking
		proposing to remand TPL-001-2. NERC has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	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.	
4	February 7, 2013	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.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	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.

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.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	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	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	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	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

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.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   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[10] resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

ii. Loss of the use of a large body of water as the cooling source for generation. iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. 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[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] 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

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
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. 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:

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
a. A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times; b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communication system that is both -monitored and reported at a Control Center ~~shall not be considered non-redundant~~); c. A single station dc supply associated with protective functions required for Normal Clearing, (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit ~~shall not be considered non-redundant~~); d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (~~except a single~~the trip coil may be excluded if it ~~that~~ is both monitored and reported at a Control Center ~~shall not be considered non-redundant~~).

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

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

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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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 in Protection Systems, as identified in:
  - Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011; and
  - the report dated September 2015 by two subcommittees under NERC Planning Committee , the System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee, titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 (October 17, 2013) approving Reliability Standard TPL-001-4, relating to:
  - modeling known outages with a duration of less than six months (paragraph 40); and
  - adding stability analysis for the outage of major Transmission equipment with a lead time of one year or more (paragraph 89); and;
- To replace references to the Reliability Standards MOD-010 and MOD-012, which have been superseded by MOD-032.

General Considerations

The standard will become effective 36 months following regulatory approval. The 36-month period provides time for Planning Coordinators and Transmission Planners to develop, among other things:

- A procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- Coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional analysis required due to changes in the standard.

Following this 36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5 for Category P5 planning events involving single points of failure in Protection Systems.

Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments **<u>but the planned System shall continue to meet the performance requirements in Table 1</u>**" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation plan reflects consideration that Planning Coordinators and Transmission Planners will need time to conduct the new studies and analyses in order to coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5 (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2, Part 2.7 for the non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in those jurisdictions where governmental approval is required.

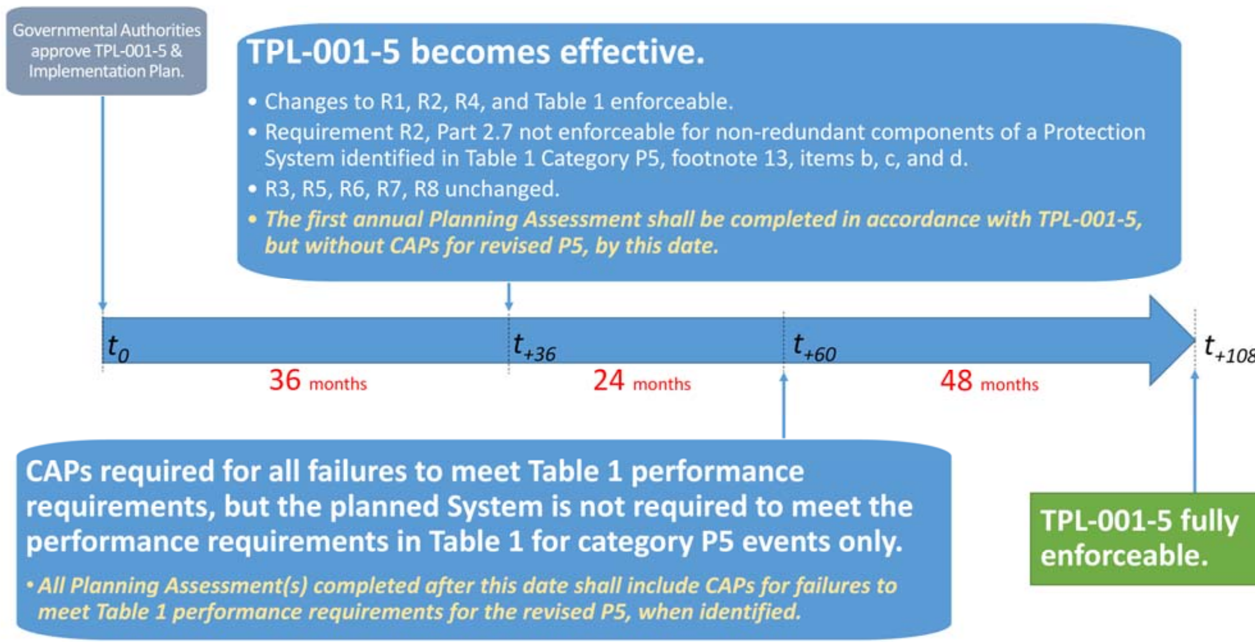


Figure 1 Implementation Plan Timeline

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 a, b, c, and d

Entities 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 a, b, c, and d until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5 with the bolded part of Requirement R2, Part 2.7 that states: "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.**"

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) 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 a, b, c, and d by 24 months after the effective date of the standard.

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.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

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~~in Protection Systems, as identified in~~-~~:
  - o Federal Energy Regulatory Commission (FERC) Order No. 754, issued on September 15, 2011~~,~~; and
  - o the report dated September 2015 by two subcommittees under NERC Planning Committee , the 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~~) approving Reliability Standard TPL-001-4, relating to:
  - o modeling known outages with a duration of less than six months~~;~~ (paragraph 40); and
  - o adding stability analysis for the outage of major Transmission ~~E~~equipment with a lead time of one year or more~~.~~ (paragraph 89); and;
- To replace references to the Reliability Standards MOD-010 and MOD-012~~ standards~~, which have been superseded by ~~the~~ MOD-032~~ Reliability Standard~~.

General Considerations

RELIABILITY CORPORATION

~~This implementation plan provides 36 months until the~~The standard will become effective ~~date of the Standard, providing~~36 months following regulatory approval. The 36-month period provides time for 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 procedure or technical rationale for selecting known outages of generation and Transmission Facilities;
- ~~A process for establishing coordination~~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~~.~~ required due to changes in the standard.

~~In addition,~~
Following this ~~implementation plan includes~~36 month period, an additional 24-month period allows time for the development of Corrective Action Plans (CAPs) under TPL-001-5 ~~to address newly-added studies~~ for Category P5~~ and P8~~ planning events involving single points of failure ~~on~~in Protection Systems.

~~This extended implementation period for the~~Transmission Planners and Planning Coordinators shall have an additional 48 months beyond the time by which CAPs must be developed to comply with the bolded part of Requirement R2, Part 2.7 that states: "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**", ~~acknowledges that failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed~~" for P5 planning events for non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d.

This implementation ~~period~~plan reflects consideration that Planning Coordinators and Transmission Planners will need time ~~beyond that provided~~ to conduct the new studies and ~~analysis~~analyses in order to ~~develop processes for coordination~~coordinate with asset owners and protection engineers to identify appropriate CAP actions and establish the associated timetables for completion. This includes any necessary CAP(s) to address System performance issues for studies involving Table 1 Category P5~~ and P8 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 non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13.

~~Lastly, the provisions related to CAP 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.~~
Please see Figure 1 Implementation Timeline below for an illustration of the 108-month implementation timeline in those jurisdictions where governmental approval is required.

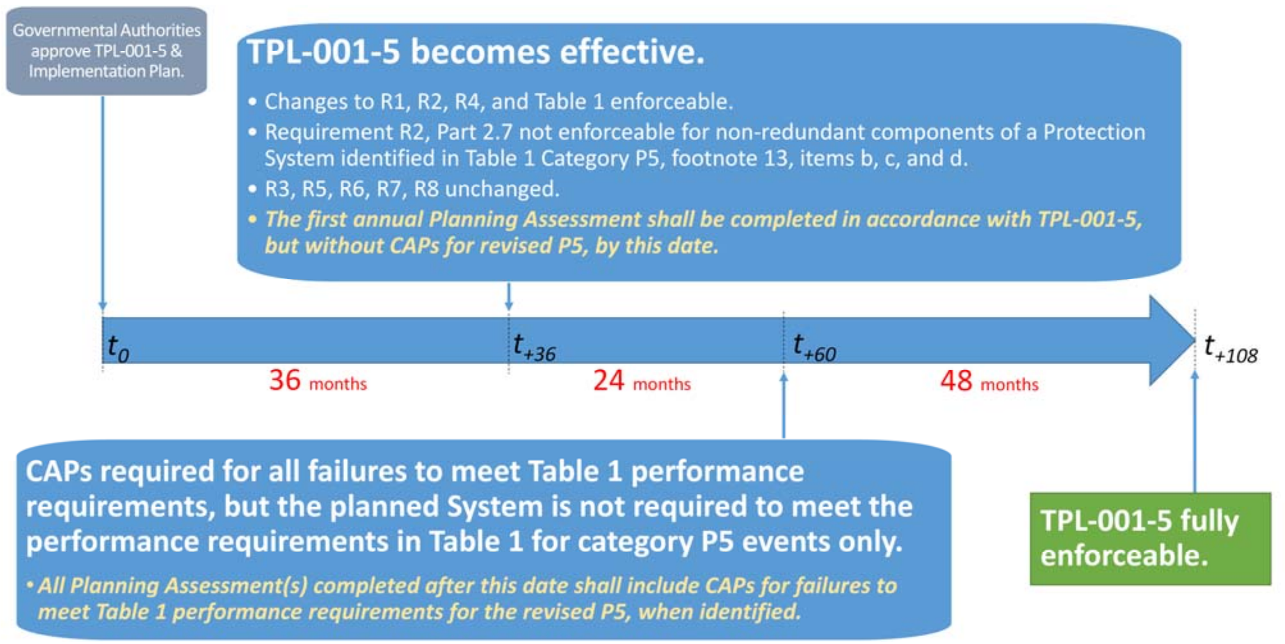


Figure 1 Implementation Plan Timeline

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 a, b, c, and d ~~and P8~~

Entit~~l~~ies 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 a, b, c, and d ~~or P8~~ until 24 months after the effective date of Reliability Standard TPL-001-5.

For CAPs developed to address failures to meet Table 1 performance requirements for ~~P5 or P8 events only, Transmission Planners~~the P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and ~~Planning Coordinators~~d, entities shall not be required to comply until 72 months after the effective date of Reliability Standard TPL-001-5 with the ~~section~~bolded part of Requirement R2, Part 2.7 that states: "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~~", until 96 months after the effective date of Reliability Standard TPL-001-5.~~."

~~**Note Regarding CAPs**~~
~~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, CAP 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 ~~without CAPs for revised P5 or P8~~ in accordance with TPL-001-5 (without CAP(s) for the revised P5 planning event) by the effective date of the standard.

Each responsible entity shall develop any required CAP(s) 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 a, b, c, and d ~~and P8~~ by 24 months after the effective date of ~~Reliability Standard TPL-001-5~~the standard.

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 instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System 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 Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; 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 Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

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:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

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.

Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 **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. **1.1** System models shall represent: **1.1.1.** Existing Facilities	TPL-001-5, Requirement R1 **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-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:	Requirement R1 body has been updated to reference MOD-032 standard number in body of requirement. Requirement R1, Part 1.1.2 and subparts have been deleted. Selection of known outages will be addressed in Requirement R2, Parts 2.1.4 and 2.4.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. **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	**1.1.1.** Existing Facilities. ~~**1.1.2.** Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:~~ ~~**1.1.2.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for~~	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	~~P1 events in Table 1 when concurrent with the selected known outage(s); and~~ ~~1.1.3.0. Does not exclude known outage(s) solely based upon the outage duration.~~ ~~1.1.4.~~1.1.2. New planned Facilities and changes to existing Facilities. ~~1.1.5.~~1.1.3. Real and reactive Load forecasts. ~~1.1.6.~~1.1.4. Known commitments for Firm	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Transmission Service and Interchange. ~~1.1.7.~~1.1.5. Resources (supply or demand side) required for Load.	
TPL-001-4, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	TPL-001-5, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	No modifications made.
TPL-001-4, Requirement R2 R2 Part 2.1.4 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	TPL-001-5, Requirement R2 R2 Part 2.1.3 2.1.43For 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	Requirement R2, Part 2.1.4 moved to Requirement R2, Part 2.1.3

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	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.	
TPL-001-4, Requirement R2 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	TPL-001-5, Requirement R2 ~~2.1.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in~~	Requirement R2 Part 2.1.3 moved to Requirement R2 Part 2.1.4 A properly planned Transmission system should facilitate maintenance outages

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
conditions when known outages are scheduled.	~~Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.~~ 2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planners's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has	without Non-Consequential Load Loss, maintain a stable System without Cascading and uncontrolled islanding. (FERC Order 786, Paragraph 41). Therefore, consistent with the principle of TPL-001-5 Requirement R3, Part 3.4 which requires the Transmission Planner and Planning Coordinator to identify those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, only those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES are to be assessed for System models that include known outages pursuant to Requirement R2, Part 2.1.4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1	
TPL-001-4, Requirement R2 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 studied. The studies 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.	TPL-001-5, Requirement R2 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 ~~studied~~assessed. Based upon this assessment, an~~The studies~~ 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.	Requirement R2, Part 2.1.5 Document internal conforming as reflecting in R2, Part 2.4.5
TPL-001-4, Requirement R2 2.4.3. 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	TPL-001-5, Requirement R2 2.4.43. 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	Requirement R2, Part 2.4.3 has been moved back to 2.4.3 as it was in TPL-001-4.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	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.	
	TPL-001-5, Requirement R2 ~~2.4.3. P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, 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.~~3~~4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System	TPL-001-5, Requirement R2, Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.4. For reasons similar to those justifying changes to

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.	Requirement R2 Part 2.1.4, the Transmission Planner and Planning Coordinator shall identify those P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES to be assessed for System models that include known outages pursuant to Requirement R2 Part 2.4.4.
	TPL-001-5, Requirement R2	TPL-001-5, Requirement R2, Part 2.4.5

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.	Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.
TPL-001-4, Requirement R2 Requirement R2 Part 2.7 **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	TPL-001-5, Requirement R2 Requirement R2 Part 2.7 **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	<u>TPL-001-5, Requirement R2,</u> <u>Requirement R2, Part 2.7</u> Changed Requirement subpart reference in Requirement 2, Part R2.7 in standard.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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:	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~~3 and 2.4.3. The Corrective Action Plan(s) shall:	
TPL-001-4, Requirement R2, Part 2.7 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.	TPL-001-5, Requirement R2, Part 2.7 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.	Requirement R2, Part 2.7 Updated to reflect NERC Glossary Term

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Installation, modification, or removal of Protection Systems or Special Protection Systems. • 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	• Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~Remedial Action Schemes. • 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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	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.	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R3 **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	TPL-001-5, Requirement R3 **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. <u>If</u>	<u>Requirement R3, Part 3.2</u> Document internal conforming clean-up to move the last sentence of Requirement R3, Part 3.5 to Requirement R3, Part 3.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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. **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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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.	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
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	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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
which may impact their Systems are included in the Contingency list. 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.	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.~~	
TPL-001-4, Requirement R4 Parts 4.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R4 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 is not considered pulling out of synchronism.	TPL-001-5, Requirement R4 TPL-001-4, Requirement R4 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~~ Remedial Action Scheme is not considered pulling out of synchronism.	Requirement R4, Part 4.1.1 Updated to reflect NERC Glossary Term
TPL-001-4, Requirement R4 **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.	TPL-001-5, Requirement R4, **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	TPL-001-5, Requirement R4, Part 4.2 Prior to this change, TPL-001-4 Requirement R4, Part 4.5 discussed analysis performed during studies referenced in TPL-001-4 Requirement R4, Part 4.2. To eliminate confusion and better separate the discussion of studies and analysis from the discussion of the necessary pre-conditional selection of extreme events in Table 1 that are expected to produce more severe System impacts, identical language from Requirement R4, Part 4.5 was moved to Requirement R4, Part 4.2.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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~~ 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	Requirement 4, Part 4.1.1

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. <u>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</u>	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	the event (s) shall be conducted. ~~4.4.~~4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall: ~~4.4.1.~~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: ~~4.4.1.1.~~4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	high speed reclosing into a Fault where high speed reclosing is utilized. ~~4.4.1.2.~~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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	any assumptions made. ~~4.4.1.3.~~4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models. ~~4.4.2.~~4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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. ~~4.5.~~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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	available as supporting information. ~~4.5.1.~~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. ~~4.6.~~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	

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	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.~~	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

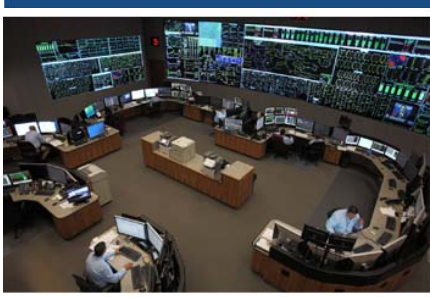
NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2015-10

Technical Rationale for TPL-001-05

October 2018

RELIABILITY | ACCOUNTABILITY

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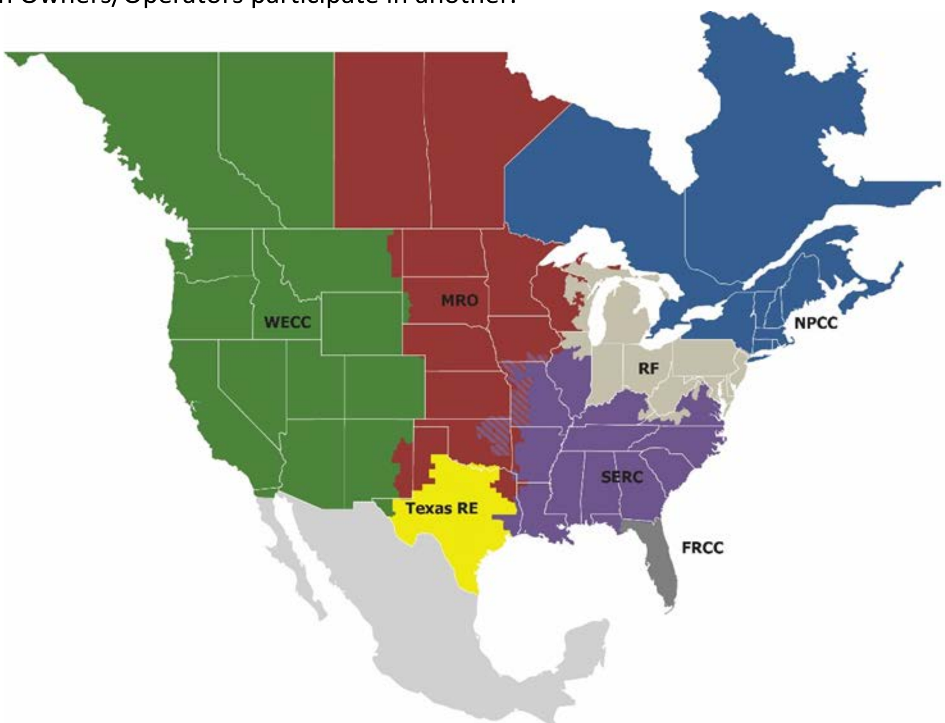
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and stability analysis for spare equipment strategy , and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standard Drafting Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in both the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC. In "Table 1 – Steady State and Stability Performance Planning Events," the Category P5 event incorporates Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two causalities, and also that fault severity and acceptable consequence of failure of a non-redundant component of a Protection System should be differentiated. Footnote 13 of the "Table 1 – Steady State & Stability Performance Footnotes" describes the non-redundant Protection System components to be considered for Category P5 Planning Events and Stability Extreme Events.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, that Category P3 and P6 do not sufficiently cover planned maintenance outages, and the Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration, shift the consideration of known outages from Requirement R1, which requires what System models shall represent, to Requirement R2, Parts 2.1 and 2.4, which require the study and assessment of known outages. Further, proposed revisions include a requirement to document an outage coordination procedure or the technical rationale for the determination of which known outages to study. Proposed revisions also included the addition of stability assessment for long lead equipment that does not have a spare.

Summary of proposed revisions

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Removed this requirement.
- Requirement R2, Part 2.1.4 – Added model conditions for steady state analysis of P0 and P1 events for known outages.
- Requirement R2, Part 2.4.4 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R3, Part 3.2 – Document internal conforming clean-up to incorporate the last sentence of Part 3.5.

- Requirement R4, Part 4.2 – Document internal conforming clean-up to incorporate the last sentence of Part 4.5.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify the SPF that should be considered.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with SPF in Protection Systems. As a follow-up to a NERC Technical Conference where the risks and concerns associated with SPF were discussed, the NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order No. 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* and the *Informational filing of the North American Electric Reliability Corporation in Response to Order No. 754* to the FERC provide extensive general discussion about the reliability risks associated with a SPF.

The SDT strongly considered the recommendations of the SPCS and SAMS report, recognizing that the purpose of that report was to determine whether a reliability concern existed demanding NERC to address the study of SPF on Protection Systems. The formation of the Project 2015-10 directly resulted from the SPCS and SAMS report recommendations. However, the SDT's obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments which adequately account for the reliability risk posed by SPF on Protection Systems.

FERC Order No. 786

In FERC Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order No. 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System (BES) were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In FERC Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the technical conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC technical conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC Planning Committee (PC) and Operating Committee (OC), summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated with SPF in Protection Systems that warrants further action.

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[3] *See [Industry Advisory: Single Point of Failure](http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf)*
http://www.nerc.com/files/Final_Order_754_Informational_Filing_3-15-12_complete.pdf

To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order No. 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SDT strongly considered the recommendations of the SPCS and SAMS report, as specified by the Project 2015-10 Single Points of Failure Standards Authorization Request (SAR). The SDT recognized that its obligation was to consider the reported recommendations and translate them into proposed TPL-001-5 Reliability Standard requirements that are meaningful to Planning Coordinators and Transmission Planners for performance of annual TPL Planning Assessments. The SPCS and SAMS report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 SDT are summarized in the following section.

Revisions to TPL-001-4

Single Points of Failure – Category P5 Planning Events

The SPCS and SAMS report states, "Analysis of the data demonstrates the existence of a reliability risk associated with single points of failure in protection systems that warrants further action. The analysis shows that the risk from single point of failure is not an endemic problem and instances of single point of failure exposure are lower on higher voltage systems. However, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify protection systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a protection system single point of failure exists)".

The modifications to the Category P5 Planning event description are intended to be aligned with the changes to the Table 1, Footnote 13. The SDT has modified Table 1, Footnote 13 to capture the SPCS/SAMS recommendations for Category P5 events, which expands beyond the previously limited set of relays identified in TPL-001-4, to capture the identified SPF of concern. Footnote 13 describes the non-redundant Protection System components to be considered for Category P5 Planning Events, and is discussed further below.

The Table 1 Category P5 event describes a Contingency where a single line-to-ground (SLG) fault occurs and Delayed Fault Clearing results due to the failure of the Protection System, protecting the Faulted element, to operate as designed. Typically, the two most important aspects of the P5 event that affect simulation are the magnitude of SLG fault current and the mode of Protection System failure leading to Delayed Fault Clearing. The latter is especially important and the mode of Protection System failure details make the P5 event unique. The Transmission Planner or Planning Coordinator must be cognizant of the time period during which the Protection System removes Elements from service, as well as the sequence of their removal during isolation of the fault. By definition, Normal Clearing is not expected when a non-redundant component of a Protection System is simulated to have failed; the P5 event implies that the Protection System does not operate as designed to clear the SLG fault in the time normally expected with proper functioning of the installed Protection System. Therefore, when a non-redundant component of a Protection System fails, Delayed Fault Clearing results. This means that correct operation of the backup Protection System occurs with the intentionally designed time delay before fault clearing. Additionally, there may be significant differences in final System configuration due to the Protection System operation to clear the faulted Element. For example, more System Elements may be removed from service when the backup Protection System operates, consistent with Delayed Fault Clearing, than may be expected during primary Protection System operation expected for Normal Clearing. The expected time delays for Protection System operation are critical for proper simulation of the P5 event.

It is anticipated that the most cost-effective Corrective Action Plans to address unacceptable system performance for the P5 Planning Events will likely be to add Protection System component redundancy, consistent with the components to be considered in Footnote 13. Protection System redundancy changes to address Category P5

Event concerns should also reduce or even negate non-redundant components that need to be considered in assessing System performance resulting from simulation of the 2e-2h Extreme Events; hence, potentially mitigating many concerns.

Clarification: Why address SPF in TPL-001 and not create a new Reliability Standard for this purpose?

As part of the recommendations from the SPCS and SAMS report, the option to create a new Reliability Standard to address SPF in the Protection System was considered. Both a new TPL standard for planning-related studies and assessment, as well as a new Protection and Control standard to specify Protection System redundancy were debated by SPCS and SAMS. Ultimately, the recommendation of the SPCS and SAMS report, leading to the formation of the Project 2015-10 SDT, focused upon the simulation and study assessment of the Transmission system given non-redundant components of the Protection System instead of mandating a level of redundancy across a diverse set of equipment and utilities in North America.

It is important to emphasize that modifications to the TPL-001-5 Table 1 Category P5 Planning Event, the TPL-001-5 Table 1 Extreme Stability Events, and related changes to Table 1, Footnote 13 do not establish or mandate a level of redundancy for Protection Systems. Quite the contrary: the modifications presented in TPL-001-5 require planning entities to consider the non-redundant components of Protection Systems that may exist within their respective Systems, to execute appropriate studies, and to assess the impacts that these SPF may have upon the ability to meet Table 1 System performance requirements given Delayed Fault Clearing. TPL-001-5 does not mandate redundancy; TPL-001-5 requires that some non-redundancy components of a Protection System be considered during annual Planning Assessments.

Clarification: Why is consideration of fault duration significant for the P5 Planning Event?

A Protection System is designed to isolate faulted equipment within an expected time duration following fault initiation. When the Protection System does not operate as designed or fails to isolate faulted equipment within the time normally expected with its proper functioning, backup protection capabilities must act to clear the fault. The SDT recognized that Protection Systems used for backup protection are designed with intentional time delays that inherently allows primary protection to actuate first. This is consistent with the Table 1 Planning Event P5 which is characterized by its prescribed Delayed Fault Clearing. The SDT recognized that the sequencing, causality, and mode of failure of a non-redundant component of a Protection System leads to Delayed Fault Clearing by the operation of backup protection, whether local (e.g., breaker failure initiation) or remote (e.g., remote-end terminal tripping consistent with zonal backup protection). The SDT believed the existing defined terms Normal Clearing and Delayed Fault Clearing were appropriate for the revised Table 1 Planning Event P5, as well as the revised Table 1 Footnote 13.

Clarification: What is the difference between a top-down versus bottom-up approach to Category P5 Events?

As part of simulating and analyzing results of P5 Event assessments, two common approaches to the Stability portion of simulations may be appropriate for planning entities to undertake. The first, referred to as the top-down approach, may initially focus upon determining critical clearing times for an entity's System topology given SLG faults. Once critical clearing times are obtained, the planning entity has the opportunity to collaborate with System Protection personnel to assess whether the installed Protection System may achieve the required performance. An advantage of the top-down approach is that the analytical burden to determine critical clearing times is front-loaded upon the planning entity and specific details regarding the Protection System are unnecessary prior to executing dynamics simulations. Conversely, the bottom-up approach may commence by the planning entity requesting the detailed causality and clearing times for SPF on the Protection System from Protection System personnel, requiring an extensive review of installed Protection Systems at the outset. While this approach may delay the execution of P5 Event studies, it may eliminate System topology that is not susceptible to SPF on the Protection System based upon Protection System personnel input and reduces the planning entity's dynamics simulation burden. Whether utilizing a top-down, bottom-up, combination of the two, or any other appropriate approach, the obligation specified in Table 1, Footnote 13 is for the planning entity to consider the non-redundant components of a Protection System that may lead to Delayed Fault Clearing when simulating the P5 Event.

Clarification: Is backup protection redundant?

The majority of BES Protection Systems are designed with overlapping zonal protection, including backup systems which eventually clear a fault in the event of a failure of the Protection System which is designed for Normal Clearing. Backup Protection Systems are not redundant for purposes of TPL-001-5 Table 1, Category P5 Events because they result in Delayed Fault Clearing and/or trip more Elements than the primary Protection System designed for Normal Clearing. Where the Protection System is designed with backup protections, the backup protection clearing time for a SLG fault must be the same as the clearing time for the primary Protection System designed for Normal Clearing, and must trip identical Elements, in order for the backup Protection System to be considered redundant to the primary Protection System. The SDT expects this type of design to be rare in its implementation, and correspondingly, backup protection is not considered redundant.

Table 1, Footnote 13

Footnote 13 is included in the TPL-001-5 Reliability Standard for the purpose of focusing the Transmission Planner and Planning Coordinator consideration of non-redundant components of a Protection System that may, when they fail, lead to Delayed Fault Clearing of the SLG fault simulated as part of the P5 event.

The SPCS and SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

A factor that the SDT considered when seeking to translate the SPCS and SAMS recommendations into the proposed TPL-001-5 Table 1, Footnote 13 was the need for Planning Coordinators and Transmission Planners to collaborate with System Protection personnel. The SDT recognized that the planning entities do not always have enough information alone to consider Protection System modes of failure or Delayed Fault Clearing than may result. Likewise, the SPCS and SAMS recommendations were adapted to target the potential non-redundant components of a Protection System that may likely need System Protection personnel input when determining how study simulations, performed by the planning entity, should be executed. Based on discussion and industry comment, the SDT revised Footnote 13 to clarify the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;

- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS and SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13. Similarly, control circuitry whose failure does not prevent Normal Clearing of a fault, such as reclosing circuitry and reclosing relays, is omitted from Footnote 13 consideration.

Clarification: Does Footnote 13 prescribe redundancy?

It is emphasized that Footnote 13 does not prescribe any level of redundancy; on the contrary, Footnote 13 gives those non-redundant components of a Protection System that shall be considered for simulation of the Table 1 Planning Event P5 and Table 1 Extreme Events Stability column 2e-2h. Further, it is the Table 1 Planning Event P5 which prescribes the required System performance. The consideration of non-redundant components of a Protection System is necessary to properly simulate the Table 1 Planning Event P5 for the purpose of assessing whether required System performance is achieved. If, after proper consideration and simulation, required System performance is achieved, then there may be no impetus to make non-redundant components of a Protection System redundant. On the other hand, after proper consideration and simulation it is demonstrated that required System performance is not achieved, making non-redundant components of a Protection System redundant may be but one of many alternatives for corrective actions to obtain required System performance.

Clarification: Why is monitored and reported to a Control Center used in parts of Footnote 13?

The SDT recognized that some components of a Protection System may be monitored and their integrity reported to a Control Center. Different than an indication of a component failure that may be displayed in a remote site or in a location that may go unnoticed for a period, reporting to a Control Center implies that an unsatisfactory condition would be identified and corrective action be directed in short order. It is noted that short order is consistent with the “within 24 hours of detecting an abnormal condition” recommendation of the SPCS/SAMS report. Given that a risk-based approach to non-redundant components of a Protection System is appropriate, the SDT believed that components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation.

Clarification: Why are relays that respond to electrical quantities addressed?

Noting that Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1 require simulation of Protection System action, the SDT sought to limit the scope of Footnote 13a with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. A SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the SDT did not include backup protective relays in the scope of Footnote 13a given that a SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The SDT recognized that BES Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be a SPF, an internal transformer tank fault may not lead to Delayed Fault Clearing given the sudden pressure protection, provided, in this example, that the resulting clearing time is similar to that achieved with the differential relay. Subsequently, the P5 event, for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay if the resulting clearing time is similar to that achieved with the differential relay. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event (See Figure 1 and 2).

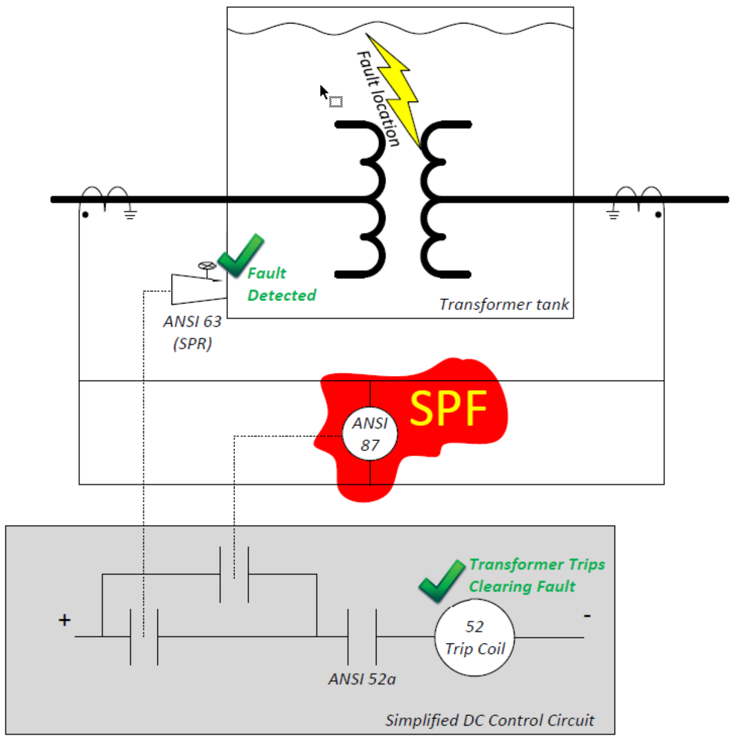

Figure 1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

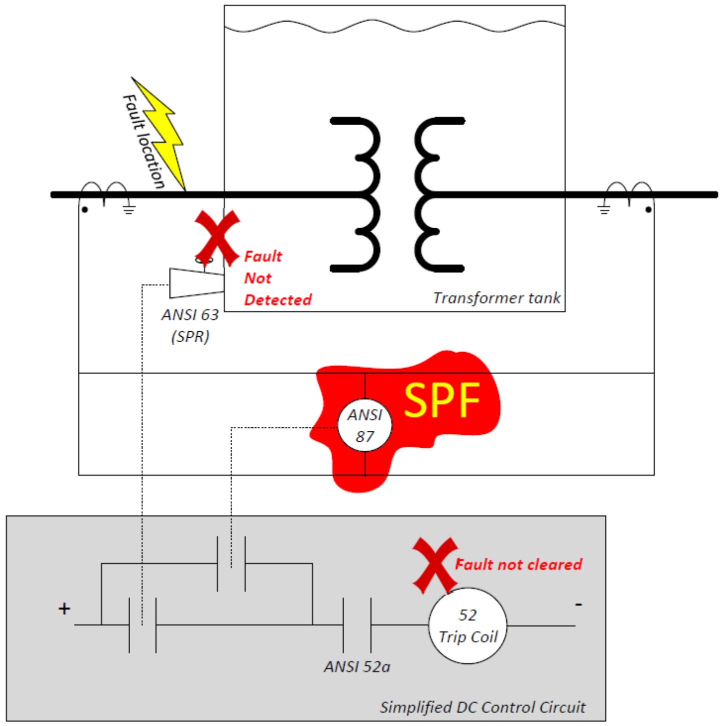

Figure 2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Clarification: What is comparable and what is not comparable for purposes of footnote 13?

The use of "comparable" in Table 1, Footnote 13a applies only to alternatives for a single protective relay that responds to electrical quantities. For an alternative to be comparable to a single protective relay that responds to electrical quantities, the alternative must operate as designed to clear the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly. Clearly, any alternative to a single protective relay that responds to electrical quantities may result in a different Element tripping sequence, leading to a different System topology after fault clearing which must be considered. Therefore, a comparable alternative to a single protective relay that responds to electrical quantities must result in fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements.

Clarification: Are separate Normal Clearing times comparable?

The SDT cannot anticipate all Protection System designs. However, the SDT's intent for alternatives to a single protective relay that responds to electrical quantities is implicit in the principle of comparable Normal Clearing times. In some cases, multiple layers of protection may overlap towards achieving a common System protective objective: to provide Normal Clearing. Examination of this design towards the common objective may indicate the Normal Clearing times are comparable. An example of this type of design may be a piloted relay for high-speed fault clearing used in conjunction with a non-piloted relay for primary or fast fault clearing. While these two relays may have different Normal Clearing times, their protective objective is common: to provide Normal Clearing. The clearing times of these two relays may be different, but are likely comparable. The applicable entity must understand the design of their own Protection System for the purpose of considering non-redundant components. Moreover, determination of whether alternatives, which may or may not respond to electrical quantities, provide comparable Normal Clearing times must be made with regard to the Protection System design, the expected fault clearing time, and the protective objective of its proper functioning.

Clarification: Why are communication-aided Protection Systems addressed?

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The SDT augmented the SPCS/SAMS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The SDT concluded that, although the failure of communication-aided Protection Systems may take many forms, by monitoring and reporting the status of these systems, the overall risk of impact to the BES can potentially be reduced to an acceptable level. However, monitoring and reporting the status of these systems can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of this failed component. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Clarification: Why are DC supplies addressed?

The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding station Protection System DC supply. Failure of a single station Protection System DC supply is a significant point of failure as it will prevent the operation of all local protection, including back-up protection. The SDT partly modified the SPCS/SAMS recommendation regarding single station DC supply, including removal of the specific requirement that reporting the detection of an abnormal condition to a location where corrective action can be initiated must occur within 24 hrs. This modification recognizes the wide variety of reporting and monitoring that exists. However, it remains the intention of Footnote 13c, that monitoring and reporting the status of the DC supply can only really be considered as a sufficient alternative to physical redundancy if the result is prompt notification and remediation which minimizes the exposure to and consequence of DC supply failure. Similar to as noted with communication-aided Protection Systems, most new Protection Systems include DC supply status alarms which are monitored at centralized Control Centers; however, they may not necessarily be monitored for both low voltage and open circuit. Therefore, this requirement may be more applicable to legacy systems.

Clarification: What differentiates a single station DC supply (Footnote 13c) from a single control circuitry (Footnote 13d)?

The station DC supply includes station battery, battery chargers and non-battery-based dc supply, as enumerated in the NERC Glossary of Terms definition of Protection System. The control circuitry includes everything from where the station DC supply terminates through and including the trip coils, including the wiring, as well as auxiliary and lockout relays. Further, the NERC Technical Paper *"Protection System Reliability Redundancy of Protection System Elements"* (November 2008) shows a demarcation between DC supply and the remainder of DC control circuitry. The SAMS and SPCS report and recommendations align with Figure 5-12 from this technical paper, shown below as Figure 3.

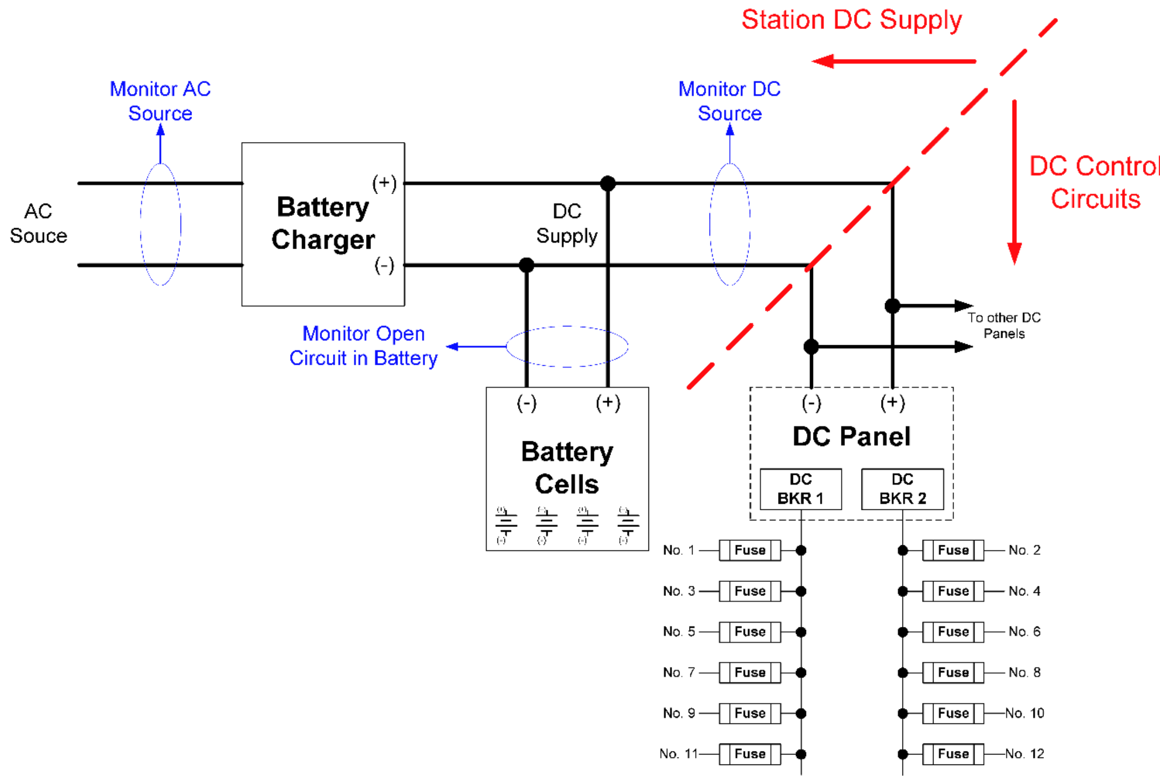

Figure 3 – Station DC supply and monitoring (Figure 5-2, from NERC Technical Paper "Protection System Reliability Redundancy of Protection System Elements", Nov 2008)

Simply monitoring for low voltage on the DC supply may omit situations where the DC supply voltage is satisfactory but the source path to DC control circuits may be open circuited. Thus, monitoring for low voltage and open circuit of the DC supply should be considered. Additionally, while the wiring in both the DC supply and the DC circuit have lower probabilities of failure as compared to other Protection System components, the SPCS and SAMS report identified this as a SPF risk.

Clarification: Is a battery charging system appropriate redundancy for the battery?

Battery chargers may not be of sufficient power to source current necessary to operate one or more breakers. For example, it is unlikely that a battery charger without a station battery in parallel would be capable of opening several breakers when demanded by a bus differential Protection System operation. Therefore, a battery charger cannot take the place of a redundant battery DC supply.

Clarification: Why is control circuitry addressed?

The SDT adopted the fundamental principles of the SPCS/SAMS recommendations regarding Protection System DC control circuitry. Failure of a Protection System single control circuitry is a significant point of failure as it will prevent proper tripping and, depending upon its design and mode of failure, may also prevent the initiation of breaker failure protection. Breaker failure is addressed by the Table 1 Planning Event P4 and is discussed in the next section. Further, most, if not all, constituent parts of the control circuitry are generally unmonitored, may fail, and may remain undetected until periodic testing is conducted. This is particularly significant for non-redundant auxiliary relays or lockout relays within the control circuitry because they may be used for multiple functions, such as multiplexing trip signals for differential or breaker failure initiation. Single control circuitry should be considered a non-redundant component of a Protection System given that Delayed Fault Clearing, including significantly delayed remote end or backup clearing, is expected when the non-redundant auxiliary or lockout relay device within the single control circuitry fails.

The single control circuitry is demarcated from the DC supply through and including the trip coil(s) for the purpose of including all devices in the control circuitry which, if failed, may prevent proper Protection System action leading to Delayed Fault Clearing. Trip coils are commonly employed in pairs (dual) for the purpose of incorporating redundancy to actuate the tripping of a circuit breaker or other interrupting device. However, the SDT partly modified the SPCS/SAMS recommendation regarding single control circuitry recognizing that some Protection System designs include a single trip instead of dual trip coils. When a single trip coil is employed, monitoring and reporting the status of the single trip coil can be considered as a sufficient alternative to its physical redundancy given that prompt notification and remediation is expected which minimizes the risk the trip coil failure. However, the trip coil(s), whether implemented singly or in pairs, are only part of the single control circuit; all its constituent parts should be included when considering whether the single control circuit may be a non-redundant component of a Protection System.

The Distinction between Category P4 and Category P5 Planning Events

"Table 1 – Steady State and Stability Performance Planning Events," makes a clear distinction between breaker failure, Category P4 Planning Events, and failure of a non-redundant component of a Protection System, Category P5 Planning Events. The sequence and timing of Protection System action leading to Delayed Fault Clearing may be quite different between the two fundamentally different causalities. Category P4 events involving the failure specifically of a circuit breaker assume that only the circuit breaker has failed, and that all other protection functions, including proper initiation of local breaker failure operation, has occurred correctly. For Category P5 Planning Events, failure of the various non-redundant components of a Protection System, as enumerated in Table 1, Footnote 13, can result in a relatively broader range of final system states, resulting from the Delayed Fault Clearing associated with the specific SPF, and which may or may not resemble the system states resulting from Delayed Fault Clearing associated with circuit breaker failure. Likewise, the Delayed Fault Clearing time that results from a Category P5 Event may be significantly longer that that expected when simulating Category P4 Event.

It is noted that there may be many instances where a fault followed by a breaker failure results in the exact same study simulations as a fault followed by a failure of a non-redundant component of a Protection System. There could be slight differences in clearing times and the Planning Coordinator or Transmission Planner may choose to simulate a P4 and P5 as one study using the longest expected clearing time. However**,** in the event of a bus fault followed by a bus differential protection failure, there may be a single relay (ANSI device 86) communicating to several breakers attached to the faulted bus. A bus fault on a breaker and a half configuration or double breaker double bus configuration may be particularly problematic in this case. For the Category P5 Event simulating this type of Protection System failure, none of the breakers which should open to clear the fault will receive the appropriate signal from the failed SPF relay and will not clear the bus fault. This makes the bus differential P5 Event significantly more severe than the P4 Event. The FERC Order 754 Section 1600 Data Request was specific to bus faults followed by a SPF of the Protection System.

In some cases, a P4 Event simulation at a specific location will be the same as the P5 Event simulation. For example: the failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open to clear a fault. Therefore, the P4 Event and the P5 Event may simulate the identical causality. However, if this simulation results in a performance requirement violation, the CAP must include mitigations for the P4 Event as well the P5 Event.

Extreme Events 2e-2h listed from the stability column of Table 1

Analysis of the data collected under the FERC Order No. 754 Section 1600 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further consideration. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis should be placed on assessment of three-phase faults involving a SPF on the Protection System. This concern, made manifest through the study of a three-phase fault and a SPF on a Protection System, is appropriately addressed as an extreme event in TPL-001-5, Requirement R4, Part 4.2. While less probable than SLG faults, three-phase faults frequently initiate as single-phase-to-ground with Delayed Fault Clearing and often evolve into three-phase faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1, Category P5 Event. TPL-001-5, Requirement R4, Part 4.2, specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of extreme events. Thus, the SDT has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but encourages consideration of implementing mitigating actions if it is cost-effective to do so.

Requirement R3, Parts 3.2 and 3.5 and Requirement R4, Parts 4.2 and 4.5

The SDT proposes non-substantive editorial changes to combine part of Requirement R3, Part 3.5 with Requirement R3, Part 3.2. The rearrangement of Requirement 3, Parts 3.2 and 3.5 were done to improve consistency within the Standard and do not create any new requirements. This is also true for Requirement R4, Part 4.2 and 4.5. However, it should be noted that the evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the (extreme) event is intended to support and encourage the implementation of reasonable, cost-effective measures to lessen the risk or severity of these events.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

FERC Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The NERC SAMS also recommended modifying TPL-001-4, Requirement R1, Part 1.1.2 by removing "with duration of at least six months" and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

To understand the relationship between outage coordination and Transmission Planning Assessments, and how those relate to the FERC Order No. 786 directive and the current state of NERC Reliability Standards, SAMS considered the following:

- The duration of planned maintenance and construction outages can range from hours to many months or years. The impact that these outages can have on reliable operation of the BPS are irrespective of the duration of these outages, depending on many factors.
- Longer-term assessment of short-term outages or even longer-term outages is often considered an "academic exercise" due to concurrent outages, outage coordination practices and procedures, outage rescheduling and redesign, and alternative outage methods.
- The directives in FERC Order No. 786 pre-date the development of IRO-017-1, which was developed specifically to recognize the importance of outage coordination.
- Regional differences result in different outage coordination methods and procedures.

Revisions to TPL-001-4

Requirement R2, Parts 2.1.4 and 2.4.4

The SDT gave due consideration to the NERC SAMS recommendations and to a range of opinions and options regarding how to determine which known outages to include in the Near-Term Planning Assessment, which included varying, and sometimes conflicting, perspectives, such as that:

- the RC should not be consulted or involved at all in Planning Assessments,
- it is reasonable, appropriate, and efficient to consult with the RC,
- IRO-017 is adequate and applicable as it exists or with some modification, or
- maintenance outage selection for planning purposes should be at the sole discretion of the Transmission Planner or Planning Coordinator.

The range of these options reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these types of outages. Those differences contribute to a legitimate difficulty in designing a reasonable and cost-effective continent wide means of addressing the FERC directive. However, FERC Order No. 786 requires that the issue be addressed. The rationale for selecting the known outages to be studied must be well thought out and available. The proposed modification is for consideration of known outages beyond, and therefore outside of, the Operations Planning time horizon.

The most prominent change the SDT proposes to address the FERC directive was to migrate the assessment of known outages from Requirement R1, which requires that System models shall represent, to Requirement R2, Parts 2.1 and 2.4 which requires how analyses shall be assessed and supported by studies. The SDT believed that this proposed change to where the assessment of known outages is specified in the TPL-001-5 requirements better aligns the approach necessary for the planning entities to execute their annual Planning Assessments.

The SDT modified Requirement R2, Part 2.1.4 and 2.4.4 consistent with FERC's directive, eliminating the specified six month outage duration and recognizing the various means that Planning Coordinators and Transmission Planners currently employ to consider the maintenance outages of concern, while meeting the requirements of Order No. 786. The proposed modifications place limitations on the known outages that need to be considered. The Planning Coordinator and Transmission Planner must have either a documented outage coordination procedure or technical rationale to select which known outages shall be assessed. The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes. The technical rationale is intended to include well-reasoned technical bases for making the determination. Consistent with the intention of Order No. 786, the SDT included the specification that the limitation of known outages to be modeled cannot be based solely on the outage duration. However, the presence of other accompanying factors, which in conjunction with outage duration, may form a reasonable basis for supporting that the known outage need not be assessed. It is only necessary to consider known outages expected to cause more severe System impacts, such as those that may result in Non-Consequential Load Loss for P1 event in Table 1. This allows the Planning Coordinator and Transmission Planner to use applicable means to assess which known outages are significant and prevents the need for conducting unnecessary assessment of outages which the Planning Coordinator and Transmission Planner do not expect to be problematic. The System conditions, such as peak or Off-Peak, that are expected during the period when the known outage is planned further limits the "non-hypothetical" analyses that may be performed. While it is inappropriate to assume that all known outages simulated in conjunction with Category P0 or P1 Events are identical to Category P3 or P6 Events, past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1 . However, it is imperative for the Planning Coordinator or Transmission Planner to document the justification for

supporting the known outage exclusion based upon past or current studies and why the post-Contingency System conditions and configuration are comparable in their technical rationale.

Clarification: Does TPL-001-5 duplicate requirements of IRO-017-1 for outage coordination?

The SDT was concerned that in order for the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon, it must first assess the known outages as part of that Planning Assessment. However, if the Planning Coordinator or Transmission Planner does not know what outages to study, clearly outages may be omitted from having the opportunity for jointly developed solutions with the Reliability Coordinator, required in IRO-017-1. The SDT believed that the feedback loop between the planning entities and the Reliability Coordinator ends with the planning entities presenting their study results in the Planning Assessment, but must begin with strong collaboration and sourcing of information regarding known outages that should be studied beyond the Operations Horizon by the Reliability Coordinator. Therefore, the SDT does not believe that there is duplication between the proposed TPL-001-5 and IRO-017-1 standards. Moreover, the SDT believes there is an implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon.

FERC Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies 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. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

Clarification: Does TPL-001-5 prescribe an entity's spare equipment strategy?

No. The SDT addressed the guidance in paragraph 89 of Order No. 786 regarding stability analysis to assess System performance for conditions expected during possible unavailability of long lead time equipment in TPL-001-5 Requirement R2, Part R2.4.5. The SDT recognized that "spare equipment strategy" is not a NERC-defined term and believed it was sufficient to allow flexibility for applicable entities to conduct both steady state and stability analysis required by TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5. For example, an entity's spare equipment strategy may include the warehousing of a replacement transformer to be installed given the failure of an in-service BES transformer. When an entity's spare equipment strategy may prevent major Transmission equipment from being out-of-service for one year or more, this possible equipment unavailability need not be assessed as part of TPL-001-5 Requirement R2, Parts R2.1.5 and R2.4.5.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have “a lead time of one year or more.”
- Each long-lead time Element that is removed from service creates a new operating condition considered the “normal” (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4, Part4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4, Part 4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4, Part4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2, Part 2.4.5

Consistent with FERC’s Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 SDT revised TPL-001-4 Requirement R2, Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under Requirement R2, Part 2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity’s spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning entities and System Protection personnel that will need to collaborate when conducting the studies and submitting the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines. Coordination with Generator Owners, Transmission Owners, and Distribution Providers will be necessary to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant component of a Protection System could result in a potential reliability risk. Transmission Planners and Planning Coordinators must obtain this information, as well as resulting fault clearing times, to perform proper studies.

Standards Announcement

Project 2015-10 Single Points of Failure

Final Ballots Open through October 22, 2018

Now Available

Final ballots for **TPL-001-5 – Transmission System Planning Performance Requirements** and the **implementation plan,** are open through **8 p.m. Eastern, Monday, October 22, 2018**.

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool associated with this project can log in and submit their votes here. If you experience issues navigating the Standards Balloting & Commenting System (SBS), contact Wendy Muller.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the standard and implementation plan will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Latrice Harkness (via email) or at (404) 446-9728.

BALLOT RESULTS

Ballot Name: 2015-10 Single Points of Failure TPL-001-5 FN 4 ST
Voting Start Date: 10/11/2018 11:38:26 AM
Voting End Date: 10/22/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 254
Total Ballot Pool: 294
Quorum: 86.39
Weighted Segment Value: 66.69

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	43	0.662	22	0.338	0	4	10
Segment: 2	8	0.8	5	0.5	3	0.3	0	0	0
Segment: 3	67	1	39	0.661	20	0.339	0	0	8
Segment: 4	16	1	8	0.727	3	0.273	0	0	5
Segment: 5	65	1	31	0.633	18	0.367	0	4	12
Segment: 6	49	1	26	0.619	16	0.381	0	3	4
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.6	4	0.4	2	0.2	0	0	0
Totals:	294	6.6	158	4.402	84	2.198	0	12	40

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Negative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Laura Lee		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Negative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Negative	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Negative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Negative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Negative	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Negative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Negative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation District	Spencer Tacke		None	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Negative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Negative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh	Michael Brytowski	Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Negative	N/A
6	AEP - AEP Marketing	Yee Chou		Negative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Negative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Luminant - Luminant Energy	Kris Butler		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Negative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Negative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	N/A
7	Luminant Mining Company LLC	Brenda Hampton		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Midwest Reliability Organization	Russel Mountjoy		Negative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2015-10 Single Points of Failure TPL-001-5 Implementation Plan FN 3 ST
Voting Start Date: 10/11/2018 11:37:33 AM
Voting End Date: 10/22/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 3
Total # Votes: 255
Total Ballot Pool: 294
Quorum: 86.73
Weighted Segment Value: 72.44

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	79	1	47	0.746	16	0.254	0	6	10
Segment: 2	8	0.6	4	0.4	2	0.2	0	2	0
Segment: 3	67	1	42	0.724	16	0.276	0	1	8
Segment: 4	16	1	9	0.75	3	0.25	0	0	4
Segment: 5	65	1	35	0.729	13	0.271	0	5	12
Segment: 6	49	1	30	0.714	12	0.286	0	3	4
Segment: 7	1	0	0	0	0	0	0	1	0
Segment: 8	2	0.1	1	0.1	0	0	0	0	1
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	6	0.5	3	0.3	2	0.2	0	1	0
Totals:	294	6.3	172	4.564	64	1.736	0	19	39

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	American Transmission Company, LLC	Douglas Johnson		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Black Hills Corporation	Wes Wingen		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		None	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Frank Pace		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Buyce		Negative	N/A
1	Cleco Corporation	John Lindsey	Louis Guidry	None	N/A
1	Colorado Springs Utilities	Devin Elverdi		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	N/A
1	Corn Belt Power Cooperative	larry brusseau		Abstain	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		None	N/A
1	Duke Energy	Laura Lee		Negative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Eversource Energy	Quintin Lee		Affirmative	N/A
1	Exelon	Chris Scanlon		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	Julie Severino		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Hydro One Networks, Inc.	Payam Farahbakhsh		Abstain	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Abstain	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	KAMO Electric Cooperative	Walter Kenyon		None	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		None	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	LS Power Transmission, LLC	John Seelke		Affirmative	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Negative	N/A
1	MEAG Power	David Weekley	Scott Miller	Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Andy Fuhrman	Negative	N/A
1	Muscatine Power and Water	Andy Kurriger		Negative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Nebraska Public Power District	Jamison Cawley		Negative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Oncor Electric Delivery	Lee Maurer	Eric Shaw	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Laurie Williams		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		Affirmative	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Seattle City Light	Pawel Krupa		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Sempra - San Diego Gas and Electric	Mo Derbas		Negative	N/A
1	Sho-Me Power Electric Cooperative	Peter Dawson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Southern Indiana Gas and Electric Co.	Steve Rawlinson		None	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Negative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	John Tolo		Affirmative	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Negative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	Independent Electricity System Operator	Leonard Kula		Abstain	N/A
2	ISO New England, Inc.	Michael Puscas	John Pearson	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Negative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Abstain	N/A
3	AES - Indianapolis Power and Light Co.	Bette White		None	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	W. Dwayne Preston		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston	Darnez Gresham	Negative	N/A
3	Black Hills Corporation	Eric Egge		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Affirmative	N/A
3	City Utilities of Springfield, Missouri	Scott Williams		Negative	N/A
3	Clark Public Utilities	Jack Stamper		Affirmative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	N/A
3	Cowlitz County PUD	Russell Noble		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	Duke Energy	Lee Schuster		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Affirmative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Negative	N/A
3	JEA	Garry Baker		Affirmative	N/A
3	KAMO Electric Cooperative	Ted Hilmes		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Negative	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Negative	N/A
3	MEAG Power	Roger Brand	Scott Miller	Affirmative	N/A
3	Modesto Irrigation District	Jack Savage	Nick Braden	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	Brandon McCormick	Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	James Meyer		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bridget Silvia		Negative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Fred Frederick		None	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	TECO - Tampa Electric Co.	Ronald Donahey		None	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Negative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Clewiston	Lynne Mila	Brandon McCormick	Affirmative	N/A
4	City Utilities of Springfield, Missouri	John Allen		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Aubrey Short		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Affirmative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A
4	Modesto Irrigation District	Spencer Tacke		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Charles Wubbena		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		None	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury	Jeffrey Watkins	Affirmative	N/A
5	Black Hills Corporation	George Tatar		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		None	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Abstain	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City of Independence, Power and Light Department	Jim Nail		Negative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cleco Corporation	Stephanie Huffman	Louis Guidry	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Affirmative	N/A
5	Colorado Springs Utilities	Jeff Icke		None	N/A
5	Con Ed - Consolidated Edison Co. of New York	William Winters	Alyson Slanover	Negative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy	Jamie Prater		Affirmative	N/A
5	Exelon	Ruth Miller		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Preston Walsh	Michael Brytowski	Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Negative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Negative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Affirmative	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Negative	N/A
5	New York Power Authority	Shivaz Chopra		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	Northern California Power Agency	Marty Hostler		None	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	OTP - Otter Tail Power Company	Brett Jacobs		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		None	N/A
5	Seattle City Light	Faz Kasraie		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Brenda Atkins		None	N/A
5	Sempra - San Diego Gas and Electric	Daniel Frank		Negative	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Mark McDonald		None	N/A
5	Talen Generation, LLC	Matthew McMillan		None	N/A
5	TECO - Tampa Electric Co.	Frank L Busot		None	N/A
5	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Andrew Gallo		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Negative	N/A
6	Black Hills Corporation	Eric Scherr		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	None	N/A
6	Colorado Springs Utilities	Shannon Fair		None	N/A
6	Con Ed - Consolidated Edison Co. of New York	Christopher Overberg		Negative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		None	N/A
6	Duke Energy	Greg Cecil		Negative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Ivanc		Affirmative	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Negative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Negative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	N/A
6	Luminant - Luminant Energy	Kris Butler		Abstain	N/A
6	Manitoba Hydro	Blair Mukanik		Negative	N/A
6	Modesto Irrigation District	James McFall	Nick Braden	Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Snohomish County PUD No. 1	Franklin Lu		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Negative	N/A
7	Luminant Mining Company LLC	Brenda Hampton		Abstain	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Massachusetts Attorney General	Frederick Plett		None	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Florida Reliability Coordinating Council	Peter Heidrich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Midwest Reliability Organization	Russel Mountjoy		Negative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Negative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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Exhibit H

Standard Drafting Team Roster

Standard Drafting Team Roster

Project 2015-10 Single Points of Failure

	Name	Entity
Chair	Jonathan Hayes	SPP
Vice Chair	Delyn Kilpack	Louisville Gas & Electric and Kentucky Utilities
Members	Baj Agrawal	Arizona Public Service Company
	Chris Colson	Western Area Power Administration
	Manuela Dobrescu Dobritoiu	Hydro-Quebec
	Prabhu Gnanam	ERCOT
	William Harm	PJM Interconnection LLC
	Liqin Jiang	Duke Energy
	Ruth Kloecker	ITC Holdings
	Richard Kowalski	ISO New England
PMOS Liaison	Mark Pratt	Southern Company
NERC Staff	Latrice Harkness – Senior Standards Developer	North American Electric Reliability Corporation
	Lauren Perotti – Counsel	North American Electric Reliability Corporation