

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Version 1 of SAR posted for comment from April 2, 2002 through May 3, 2002.
2. Version 2 of SAR posted for comment from May 5, 2004 through June 5, 2004.
3. Version 3 of SAR posted on November 18, 2005.
4. SAR approved on April 30, 2006.
5. Version 1 of Supplemental SAR posted for comment from February 15, 2007 through March 16, 2007.
6. Version 2 of Supplemental SAR posted on April 9, 2007.
7. Version 1 of revised standard(s) posted for comment on September 17, 2007.
8. Version 2 of the revised standards posted for comment on August 15, 2008.

Proposed Action Plan and Description of Current Draft:

The SDT has established a schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 1Q10. The current draft is the second iteration of the revision of existing standards TPL-001 through TPL-006 and includes one revised standard, TPL-001-1, replacing TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0. TPL-005 & -006 will be addressed later in the project.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from third posting and submit revision 4 of the standard.	2Q09
2. Submit standard(s) for balloting.	3Q09
3. Submit standard(s) to BOT.	4Q09
4. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual **straight bus** substation **bus** configurations. ~~(Substation configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus-tie breakers.)~~

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions.~~

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events.

~~**Generating Unit Stability Study:** Study that focuses on an individual generating unit's or electrically closely coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.~~

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: Transmission planning period that covers Years One through five.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under voltage Load shedding, under frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.~~

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Events: Events that require Transmission system performance requirements to be met.

Planning Coordinator: ~~The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.~~

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

System Stability Study: ~~Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~

Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the ~~completion of the previous annual Planning Assessment~~ current calendar year.

A. Introduction

1. **Title:** Transmission System Planning Performance Requirements
2. **Number:** TPL-001-1
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:** ~~As per Implementation Plan (to be supplied later).~~ Requirements R1 and R7 shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption.

Except as indicated below, Requirements R2 through R6 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is 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.

- For 60 calendar months after the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-1, Table 1 are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1:

- 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.~~ Any entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet performance requirements of this Reliability Standard. Any such entity shall submit a mitigation plan to its Regional Entity outlining the steps it will take to become compliant and the date it anticipates becoming compliant. The Regional Entity and NERC shall review the mitigation plan and the Regional Entity/NERC will either approve it or remand it for changes (this could include dates, steps, etc.). If the mitigation plan is approved by the Regional Entity and

NERC and the entity completes the mitigation plan by the date contained within the mitigation plan, no penalties will be assessed. Those entities that do not meet the date outlined in an approved mitigation plan will begin settlement proceedings at that date.

B. Requirements

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. [*Violation Risk Factor: ~~TBD~~Medium*] [*Time Horizon: ~~TBD~~Long-term Planning*]

~~R1.1.~~

~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~

R1.1. Models for the Planning Assessment shall represent:

R1.1.1. Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2. New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- -Transmission Lines
- -Generators
- -Circuit breakers
- -Reactive Power devices
- -Protection System equipment
- -Control devices
- -New technologies.

R1.1.3. Real and reactive Demand of Load

R1.1.4. Firm Transmission Service

R1.1.5. Interchange

R1.1.6. Network resources required to supply Load

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare its annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses ~~including both System and Generating Unit Stability.~~ [*Violation Risk Factor: ~~TBD~~Medium*] [*Time Horizon: ~~TBD~~Long-term Planning*]

R2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and for year five.

R2.1.2. System Off-Peak Load for one of the five years.

R2.1.3. For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities variations that reflect in~~ one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

~~P.2.1.3.1. • Higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day~~ Forecasted Load and power factor.

~~P.2.1.3.2. • Modification of e~~Expected transfers.

~~P.2.1.3.3. • Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.

~~P.2.1.3.4. • Variability and outages of r~~Reactive resources capability.

~~P.2.1.3.5. •~~ Generation additions, retirements, or other dispatch scenarios.

~~P.2.1.3.6. • Decreased effectiveness of e~~Controllable Loads and Demand Side Management.

~~P.2.1.3.7. • Modification of p~~Planned duration or timing of Transmission outages.

R2.1.4. ~~In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~ 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), an analysis of the impact on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment.

R2.2. For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum~~, a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.2.1. To accommodate any known longer lead time projects that may take longer than ten years to complete, the Planning Assessment shall be extended accordingly.

R2.3. 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. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area.](#)

R2.4. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies. The following studies are required:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads. [An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.](#)

R2.4.2. System Off-Peak Load for one of the five years.

R2.4.3. For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that [are intended to stress the System with variations to reflect in](#) one or more of the following conditions [not already included in the studies](#) shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ [included in the Assessment](#):

- ~~Variations in~~ Load model assumptions.
- ~~Modification of e~~ Expected transfers.
- ~~Unavailability of long lead time Facilities~~ [Timing of the installation of new or modified Facilities.](#)
- ~~Variability and outages of r~~ Reactive resources [capability.](#)
- Generation additions, retirements, or other dispatch scenarios.

~~**R2.4.4.**In addition to those sensitivities mentioned in Requirement 2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.~~

~~**R2.5.**The Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement R5.5 with studies for the year when the following changes that could affect stability margins occur:~~

~~**R2.5.1.**New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.~~

~~**R2.5.2.**Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a~~

~~Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.~~

~~R2.6.R2.5.~~ Past studies may be used to support the Planning Assessment if they meet the following requirements:

~~R2.6.1.R2.5.1.~~ For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

~~R2.6.2.R2.5.2.~~ For steady state, short circuit, ~~Generating Plant Stability~~, or ~~System~~ Stability analysis: the ~~study present System model~~ shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Material generation changes could include:

- -The addition/deletion/change of individual generating unit capability of 20 MW or greater.
- -An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater.

~~R2.7.R2.6.~~ For Planning Events shown in Table 1—~~Steady State Performance~~ and Table 2—~~Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the~~ Tables 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall:

~~R2.7.1.R2.6.1.~~ List System deficiencies and the associated actions needed to achieve required System performance. Such actions may include: ~~installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.~~

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation or modification 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.

R.2.7.1.1.R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date.

R.2.7.1.2.R2.6.3. For the Long-Term Transmission Planning Horizon, provide an in-service year.

~~**R2.7.4.** Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.~~

R2.6.4. 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 prudent 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.

R2.7.3.R2.6.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

R2.8.1.R2.7. For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1. List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2. Be reviewed in subsequent annual Planning Assessments as to implementation status.

R2.7.R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1.

R2.9. The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to cContingencies in Table 1—Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. [Violation Risk Factor: ~~TBD~~Medium] [Time Horizon: ~~TBD~~Long-term Planning]

R3.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1—~~Steady State Performance.~~ based on the lists created in Requirement R3.4.

R3.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5.

~~R3.2.~~R3.3. Contingency analyses shall: ~~simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.~~

R3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

~~R3.2.1.~~R3.3.2. For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

~~R3.2.2.~~R3.3.3. For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation.

R3.3.4. Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, capacitors, and inductors.

~~R3.2.~~For Steady State studies:

~~R3.2.1.~~Performance criteria for System normal conditions and for Planning Events in Table 1—Steady State Performance shall be met.

~~R3.2.2.~~Evaluations shall be performed for single Contingencies (identified in Table 1—Steady State Performance).

~~R.3.2.2.1.~~ Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.

~~R.3.2.2.2. Following single Contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.~~

~~R3.3.3.R3.4.~~ Those Planning Event Contingencies in Table 1 —~~Steady State Performance not covered in Requirement R3.3.2~~ that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created, ~~and~~ ~~†~~ The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include an explanation of why the remaining Contingencies would produce less severe System results.

~~R3.4.R3.5.~~ Those Extreme Events in Table 1 —~~Steady State Performance~~ that are expected to produce more severe System impacts shall be identified, and a list of those events to be evaluated for System performance in Requirement R3.2 created, ~~and~~ ~~†~~ The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of implementing a change possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate of suchthe consequences and adverse impacts of the event(s) shall be conducted.

~~R3.5. Manual and automatic generation run back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met:~~

~~R3.5.1. All Facilities shall be operating within their Facility Ratings.~~

~~R3.4.1. Such action would not violate safety, equipment, regulatory or statutory requirements.~~

~~R3.4.2. A sustainable, stable, operating condition is maintained.~~

~~R4. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties. [Violation Risk Factor: TBD] [Time Horizon: TBD]~~

~~R5.R4.~~ For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 2 1 —Stability Performance. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise~~

~~noted:~~ [Violation Risk Factor: ~~TBD~~Medium] [Time Horizon: ~~TBD~~Long-term Planning]

R4.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 21 —Stability Performance based on the lists created in Requirement R4.4~~shall use computer Stability simulations that analyze the response of the BES.~~

R4.2. Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5.

R4.3. Contingency analyses shall:

R4.3.1. ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention.

~~R5.3.~~**R4.3.2.** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed ~~in the simulation.~~

R4.3.3. Simulate the expected operation of existing and planned devices designed to provide dynamic control of electrical system quantities. These devices include equipment such as generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

~~R5.2.~~For the System Stability study:

~~R5.4.1.~~**R4.4.** At a minimum, ~~t~~Those Planning Event Contingencies in Table 21 —Stability Performance that ~~would~~are expected to produce more severe System impacts shall be identified, ~~and a list of those Contingencies to be~~ evaluated for System performance ~~in Requirement R4.1 created;~~, ~~and~~~~t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

~~R5.3.1.~~Performance shall meet the requirements for Planning Events in Table 2 —Stability Performance.

~~R5.3.2.~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

~~R.5.3.2.1.~~ All Facilities shall be operating within their Facility Ratings.

~~R.5.3.2.2.~~Such action would not violate safety, equipment, regulatory or statutory requirements.

~~R.5.4.3.3.~~A sustainable, stable, operating condition is maintained.

~~R5.4.4.~~**R4.5.** At a minimum, ~~t~~Those Extreme Events in Table 21 —Stability Performance that ~~would~~are expected to produce more severe System impacts shall be identified ~~and a list of those events to be;~~ evaluated for System performance ~~in Requirement R4.2 created;~~, ~~and~~ ~~t~~The rationale for the

Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change possible actions~~ designed to reduce ~~or mitigate~~ the likelihood or mitigate of such the consequences of the event(s) shall be conducted.

~~R5.5.~~ For the ~~Generating Unit Stability~~ studies:

~~R5.5.1.~~ Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.

~~R5.5.2.~~ Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.

~~R5.5.3.~~ Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.

~~R5.5.4.~~ Shall meet Performance requirements for Planning Events in Table 2—Stability Performance.

R6.R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. [Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning]

R7.R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning]

R8.R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. [Violation Risk Factor: ~~TBD~~Low] [Time Horizon: ~~TBD~~Long-term Planning] ~~This distribution shall include:~~

~~R9.~~ Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. [Violation Risk Factor: ~~TBD~~] [Time Horizon: ~~TBD~~]

- ~~R10.~~ Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*
- ~~R11.~~ Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*
- ~~R12.~~ Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*
- ~~R13.~~ Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*
- ~~R14.~~ Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

C. Measures

- M1. Each Transmission Planner and Planning Coordinator shall provide evidence, such as the System model with the specified data in electronic or hard copy format, that ~~they~~ it ~~are~~ is maintaining System models, using data consistent with MOD-010 and MOD-012, simulating projected System conditions, and that the models represent the required information in accordance with Requirement R1.
- M2. Each Transmission Planner and Planning Coordinator shall provide 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. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- ~~M1.~~ Requirement R4 to be deleted.
- ~~M5.~~ M4. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R54.

M5. [Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies, of the studies utilized in preparing the Planning Assessment in accordance with Requirement R65.](#)

~~M7.~~**M6.** [Each Transmission Planner and Planning Coordinator shall provide evidence, such as a dated document, that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies for the Planning Assessment in accordance with Requirement R76.](#)

M7. [Each Planning Coordinator shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has coordinated the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890 in accordance with Requirement R87.](#)

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 Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.](#)
- [All Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.](#)
- [All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.](#)

- All studies performed in support of its Planning Assessment since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R5 and Measure M5.
- The current, in force agreement on identified responsibilities, as well as all such agreements in force since the last compliance audit, in accordance with Requirement R6 and Measure M6.

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 R7 and Measure M7.

1.5 Additional Compliance Information

None.

2 Violation Severity Levels

Standard TPL-001-1 — Transmission System Planning Performance Requirements

	Lower VSL	Moderate VSL	High VSL	Severe VSL
<u>R1</u>	<u>The Transmission Planner or Planning Coordinator’s System model failed to represent one of the sub-requirements R1.1.1 through R1.1.6.</u>	<u>The Transmission Planner or Planning Coordinator’s System model failed to represent two of the sub-requirements R1.1.1 through R1.1.6.</u> <u>OR,</u> <u>The System model did not use data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other data sources.</u>	<u>The Transmission Planner or Planning Coordinator’s System model failed to represent three of the sub-requirements R1.1.1 through R1.1.6.</u>	<u>The Transmission Planner or Planning Coordinator’s System model failed to represent four or more of the sub-requirements R1.1.1 through R1.1.6.</u> <u>OR,</u> <u>The System model did not simulate projected System conditions as described in Requirement R1.</u>
<u>R2</u>	<u>The Transmission Planner or Planning Coordinator failed to comply with one or both of the following sub-requirements: R2.8 or R2.9.</u>	<u>The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.3 or R2.7.</u>	<u>The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.</u>	<u>The Transmission Planner or Planning Coordinator failed to comply with two or more of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.</u>
<u>R3</u>	<u>The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R3.4 or Extreme Events as described in Requirement R3.5.</u>	<u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1.</u> <u>OR,</u> <u>The Transmission Planner or Planning Coordinator did not perform studies as specified in</u>	<u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1.</u> <u>OR,</u> <u>The Transmission Planner or Planning Coordinator did not perform Contingency analysis as</u>	<u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1.</u> <u>OR,</u> <u>The Transmission Planner or Planning Coordinator did not perform studies to determine that</u>

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		<p><u>Requirement R3.2 to assess the impact of Extreme Events.</u></p> <p><u>OR,</u></p> <p><u>The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.</u></p>	<p><u>described in Requirement R3.3.</u></p>	<p><u>the BES meets the performance requirements for the P0 or P1 categories in Table 1.</u></p>
R4	<p><u>The Transmission Planner or Planning Coordinator did not identify Planning Events as described in Requirement R4.4 or Extreme Events as described in Requirement R4.5.</u></p>	<p><u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1.</u></p> <p><u>OR,</u></p> <p><u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.2 to assess the impact of Extreme Events.</u></p> <p><u>OR,</u></p> <p><u>The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.</u></p>	<p><u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1.</u></p> <p><u>OR,</u></p> <p><u>The Transmission Planner or Planning Coordinator did not perform Contingency analysis as described in Requirement R4.3.</u></p>	<p><u>The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.</u></p>

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R5	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to define and document the proxies for System instability used within their analysis as described in Requirement R5.
R6	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to determine and identify individual or joint responsibilities for performing required studies.
R7	N/A	N/A	The Planning Coordinator failed to coordinate the analysis of its Planning Assessment results through an open and transparent peer review process.	The Planning Coordinator failed to distribute the results of its Planning Assessment.

E. Regional Variances

None.

Standard TPL-001-1 — Transmission System Planning Performance Requirements

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

- a. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
- b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown~~ are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.
- c. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
- d. Simulate Normal Clearing unless otherwise specified.
- e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

- ~~b.f. Facility Ratings shall not be exceeded. Unless precluded in the Requirements, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.~~ System steady state voltages and post-~~transient~~ Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).
- g. Planning Event P0 is applicable to steady state only.

Stability Only:

- h. The System shall remain stable. ¹
- ~~f. Dynamic voltages~~ Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).
- i. ~~Simulate Normal Clearing unless otherwise specified.~~

Category	Initial System Condition	Event ²	Fault Type ³	BES Level ⁴	Interruption of Firm Transmission Service Allowed ⁵	Non-Consequential Load Loss Allowed
P0 No Contingency Normal System Conditions	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 ⁶ 4. Shunt Device ⁷	3Ø	EHV, HV	No	No
		<u>5. Single Pole of a DC line</u>	SLG			
P2 Single Contingency	Normal System	Loss of one of the following: 1. <u>Opening of Breaker(s) w/o fault</u> ⁸	N/A	EHV, HV	No	No
		2. Bus Section <u>Fault</u>	SLG	EHV HV	No Yes	No Yes
		3. Internal Breaker Fault ⁹	SLG	EHV	No	No

Standard TPL-001-1 — Transmission System Planning Performance Requirements

		(Non bus-tie)	SLG	HV	Yes	Yes
		4. Internal Breaker Fault (bus-tie) ⁹	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency (Generator + I)	Loss of generator <u>unit</u> followed by System adjustments ^{10,5}	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁶ 4. Shunt Device ⁷ 5. Single pole of a DC Line	SLG <u>3Ø</u>	EHV, HV	No ¹⁰	No
		5. Single pole of a DC line	SLG	EHV, HV	No ¹⁰	No
P4 Multiple Contingency (Fault plus stuck breaker ¹¹)	Normal System	Stuck breaker ¹¹ (non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁶ 4. Shunt Device ⁷ 5. Bus Section	SLG	EHV	No ¹⁰	No
			SLG	HV	Yes	Yes
		6. Stuck breaker (bus-tie) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Planning Events, Continued

Category	Initial System Condition	Event ²	Fault Type ³	BES Level ⁴	Interruption of Firm Transmission Service Allowed ⁵	Non-Consequential Load Loss Allowed
P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component caused by the failure within of a single Protection System associated with while clearing a fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer ⁶ 4. Shunt Device ⁷ 5. Bus Section	SLG	EHV	No ¹⁰	No
			SLG	HV	Yes	Yes
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the following followed by System adj. ^{10s} : 1. Transmission Circuit 2. Transformer ⁶ 3. Shunt Device ⁷ 4. Single pole of a DC line	Loss of one of the following followed by System adjustments : 1. Transmission Circuit 2. Transformer ⁶ 3. Shunt Device ⁷ 4. Single pole of a DC line 4. Single pole of a DC line	SLG <u>3Ø</u>	EHV, HV	Yes	Yes
			SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two circuits on common structure ¹² 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

**Table 1 – Steady State & Stability Performance
Extreme Events**

Table 1 – Steady State & Stability Performance Extreme Events	
<p>Steady State & Stability For all Extreme Events evaluated:</p> <ol style="list-style-type: none"> 1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. <ul style="list-style-type: none"> 2. Simulate Normal Clearing unless otherwise specified. 3. See Requirement R3.4 4.2. See Requirement R5.5.4 	
<p>Steady State</p> <ol style="list-style-type: none"> 1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments. 2. Local area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. Loss of a tower line with three or more circuits.¹² b. Loss of all Transmission lines on a common Right-of-Way. c. Loss of a switching station or substation (loss of one voltage level plus transformers). d. Loss of all generating units at a 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: <ol style="list-style-type: none"> a. Loss of two generating plants resulting from conditions such as: <ol style="list-style-type: none"> 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. 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. <ul style="list-style-type: none"> b. Loss of two Transmission lines in different rights of way prior to System adjustments for conditions such as: <ol style="list-style-type: none"> i. Wildfires. ii. Severe weather, e.g., hurricanes, tornadoes, etc. e.b. Other events based upon operating experience that may result in wide area disturbances. 	<p>Stability</p> <ol style="list-style-type: none"> 1. With an initial condition of a single generator, Transmission circuit, DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, shunt device, or transformer prior to System adjustments. 2. Local or wide area events affecting the Transmission System such as: <ol style="list-style-type: none"> a. 3Ø fault on generator with stuck breaker¹¹ or a Protection System failure due to a single component failure within the protection system resulting in Delayed Fault Clearing. b. 3Ø fault on Transmission circuit with stuck breaker¹¹ or a Protection System failure due to a single component failure within the protection system resulting in Delayed Fault Clearing. c. 3Ø fault on transformer with stuck breaker or a protection system failure due to a single component failure within the protection system. c. 3Ø fault on bus section with stuck breaker or a protection system failure due to a single component failure within the protection system. 3Ø fault on transformer with stuck breaker¹¹ or a Protection System failure resulting in Delayed Fault Clearing. d. 3Ø fault on bus section with stuck breaker¹¹ or a Protection System failure resulting in Delayed Fault Clearing. e. 3Ø internal breaker fault¹¹. f. 3Ø fault on two or more circuits on a common structure¹². g. SLG or 3Ø fault on all Transmission lines on a common Right-of-Way right of way. h. 3Ø fault on switching station or substation (loss of one voltage level plus transformers) i. 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. System stable means:
 - a. Angular Stability:
 - i. For Planning Event P1: No generating unit or units shall be allowed to 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.
 - ii. For all other Planning Events: No generating unit or units totaling more than the Contingency + Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.
 - b. For all Planning Events evaluated: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator (or Transmission Planner if more restrictive).
2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
3. Unless specified otherwise, simulate Normal Clearing 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 fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.
4. 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 interruptions of Firm Transmission Service and Non-Consequential Load.
5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.
6. For non-Generator Step Up transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) ~~and excluding generator step up transformers~~. For generator and generator Step Up transformer outage events, the reference voltage ~~apply~~ 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.
7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
8. Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
9. 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.
10. Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must be considered.
11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated

Standard TPL-001-1 — Transmission System Planning Performance Requirements

(IPO) breaker, only one pole is assumed to remain closed. ~~The~~ stuck breaker event introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

12. Excludes circuits that share a common structure for 1 mile or less.

Table 1—Steady State Performance

~~h. Facility Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.~~

~~i. System steady state voltages and post transient voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).~~

~~j. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.~~

~~k. Consequential Load and consequential generation loss is allowed for all events shown.~~

~~l. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.~~

~~m. Simulate Normal Clearing unless otherwise specified.~~

Planning Events

Category	Initial System Condition	Event ³	BES Elements out of Service ^{2,3}		Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
			(A) > 300 KV	(B) <= 300 KV		
P0 Normal System conditions	Normal System	None	X	X	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

Version History

Version	Date	Action	Change Tracking
1	TBD	Revision of TPL-001-0 as per Project 2006-02; includes merging requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-1	Not employed due to scope of revision

|