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.
9. Version 3 of the revised standards posted for comment on May 26, 2009.

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 issues are addressed in this fourth draft.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from second posting of standard(s) and submit revision 4 of the standard(s).	4Q08
2. Respond to comments from third posting and submit revision 5 of the standard.	3Q09
3. Submit standard(s) for balloting.	4Q09
4. Submit standard(s) to BOT.	4Q09
5. 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 substation bus configurations.

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

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 and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

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

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the 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:** Requirements R1 and R8 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 R8 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 R7 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, part 2.7.5.) that would not otherwise be permitted by the requirements of TPL-001-1:
     - 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)

   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, the intent of the SDT is that 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 within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest 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. *[Violation Risk Factor: Medium] [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. 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 required to supply Load

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 past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

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 for known outages, as modeled 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 for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- 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 planned 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), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2. 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 indicated 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. The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated 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 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 for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies 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 model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5. The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

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: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

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 run 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. Such actions may 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.

2.9. The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

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 shall be performed and:

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.

3.3.2. Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.3. Ensure relay loadability limits are respected.

3.3.4. 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 of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages 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.

3.6. When manual or automatic generation runback or tripping is used to meet steady state performance requirements for planning events P1 through P7 in Table 1, the amount of generation lost shall be documented in the Planning Assessment with a description of why the generation was runback or tripped for each event.

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: A generator that pulls out of synchronism shall be tripped in the simulations and 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 shall be performed and:

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 while also considering the impact of successful or unsuccessful high speed reclosing.

4.3.2. Trip 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.

4.3.3. Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4. 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 1that 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 R4, part 4.1 created. 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 of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages 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.

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 voltage level and a maximum length of time that transient voltages may remain outside that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

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

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]*

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. *[Violation Risk Factor: Low] [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.

C. Measures

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest 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. 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.

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 R4.

M5. Each Transmission Planner and Planning Coordinator shall provide 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 evidence, such as electronic or hard copies of the studies 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 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 R7.

M8. Each Planning Coordinator and Transmission Planner 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 distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and 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 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 Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.
- All documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.
- All studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.
- 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 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.

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. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	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 System model did not represent projected System conditions as described in Requirement R1.
R2	The responsible entity failed to comply with Requirement R2, part 2.9 or 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.
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 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	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.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	3.3.	
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. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	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.
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.

	Lower VSL	Moderate VSL	High VSL	Severe VSL
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 failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

E. Regional Variances

None.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

b. Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme 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. 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:

f. Facility Ratings shall not be exceeded.

g. System steady state voltage limits 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 including 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. The System shall remain stable. [1]

k. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial System 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	No
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of Breaker(s) w/o fault [7]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (Non Bus-tie)	SLG	EHV	No	No
			SLG	HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie) [8]	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance
Planning Events

Category	Initial System 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[19]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[19]	No
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker [101])*	Normal System	Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) 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[10]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus		EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus Protection System failure)*	Normal System	Loss of multiple elements caused by the failure of a single Protection System while clearing 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[19]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adj.[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

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.[12]
b. Loss of all Transmission lines on a common Right-of-Way[12].
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:
a. Loss of two generating plants 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.
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.</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[11] or a Protection System failure resulting in Delayed Fault Clearing.
b. 3Ø fault on Transmission circuit with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
c. 3Ø fault on transformer with stuck breaker[11]or a Protection System failure resulting in Delayed Fault Clearing.
d. 3Ø fault on bus section with stuck breaker[11] or a Protection System failure resulting in Delayed Fault Clearing.
e. 3Ø internal breaker fault[11].

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>

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 for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.
2. 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 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 as defined by the Regional Entity. 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.
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 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 breaker(s) without a fault 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.
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. 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 entitled '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 Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
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 or common Right-of-Way for 1 mile or less.

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