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 second posting of standard(s) and submit revision 3 of the standard(s).	4Q08
2. Respond to comments from third posting and submit revision 4 of the standard.	2Q09
3. Submit standard(s) for balloting.	3Q09
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 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.

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. .

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.

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

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 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 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)

     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 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: Medium] [Time Horizon: Long-term Planning]*

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 prepare an 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. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R2.1. 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 R2.6:

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 R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment:

- Forecasted Load and power factor.
- Expected transfers.
- Timing of the installation of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Planned duration or timing of Transmission outages.

R2.1.4. 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, 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 R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment:

- Load model assumptions.
- Expected transfers.
- Timing of the installation of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

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

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

R2.5.2. For steady state, short circuit, or Stability analysis: the 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.

R2.6. 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 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:

R2.6.1. 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.
- 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.

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

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

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.

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

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.

R2.8. 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 simulations using models utilizing data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R3.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 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.

R3.3. Contingency analyses shall:

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.

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

R3.3.3. For all Transmission lines, studies shall consider relay loadability and identify how loadability is 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.

R3.4. Those Planning Event Contingencies in Table 1 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. 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.

R3.5. 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 R3.2 created. 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 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.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

R4.1. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in RequirementR4.4.

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

R4.3.2. Simulate generator performance under anticipated conditions including how the voltage ride through capability is analyzed.

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.

R4.4. Those Planning Event Contingencies in Table 1 – 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 R4.1 created. 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.

R4.5. 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 R4.2 created. 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 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 define and document, within their Planning Assessment, any proxies 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]*

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: Low] [Time Horizon: Long-term Planning]*

R7. Each Planning Coordinator shall coordinate 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. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

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 it 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.

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 studies utilized in preparing the Planning Assessment in accordance with Requirement R5.

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 R6.

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 R7.

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

	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Planner or Planning Coordinator's System model failed to represent one of the sub-requirements R1.1.1 through R1.1.6.	The Transmission Planner or Planning Coordinator's System model failed to represent two of the sub-requirements R1.1.1 through R1.1.6. OR 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.	The Transmission Planner or Planning Coordinator's System model failed to represent three of the sub-requirements R1.1.1 through R1.1.6.	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. OR The System model did not simulate projected System conditions as described in Requirement R1.
R2	The Transmission Planner or Planning Coordinator failed to comply with one or both of the following sub-requirements: R2.8 or R2.9.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.3 or R2.7.	The Transmission Planner or Planning Coordinator failed to comply with one of the sub-requirements: R2.1, R2.2, R2.4, or R2.6.	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.
R3	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.	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. OR The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R3.2 to assess the	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. OR The Transmission Planner or Planning Coordinator did not perform Contingency analysis as	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. OR The Transmission Planner or Planning Coordinator did not perform studies to determine that the BES meets the performance requirements for the P0 or

	Lower VSL	Moderate VSL	High VSL	Severe VSL
		impact of Extreme Events. OR The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	described in Requirement R3.3.	P1 categories in Table 1.
R4	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.	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. OR The Transmission Planner or Planning Coordinator did not perform studies as specified in Requirement R4.2 to assess the impact of Extreme Events. OR The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.	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. OR The Transmission Planner or Planning Coordinator did not perform Contingency analysis as described in Requirement R4.3.	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.
R5	N/A	N/A	N/A	The Transmission Planner or Planning Coordinator failed to define and

	Lower VSL	Moderate VSL	High VSL	Severe VSL
				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.

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 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:

f. System steady state voltages and post-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]

i. Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).

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	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
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of Breaker(s) w/o fault [8]	N/A	EHV, HV	No	No
		2. Bus Section Fault	SLG	EHV	No	No
				HV	Yes	Yes
		3. Internal Breaker Fault [9]	SLG	EHV	No	No

		(Non bus-tie)	SLG	HV	Yes	Yes
		4. Internal Breaker Fault (bus-tie) [9]	SLG	EHV, HV	Yes	Yes

Table 1 — Steady State & Stability Performance Planning Events						
Category	**Initial System Condition**	**Event** [2]	**Fault Type** [3]	**BES Level** [4]	**Interruption of Firm Transmission Service Allowed** [5]	**Non-Consequential Load Loss Allowed**
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[10]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [6] 4. Shunt Device [7]	3Ø	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
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 [6] 4. Shunt Device [7] 5. Bus Section	SLG	EHV	No[10]	No
			SLG	HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping*	Loss of one of the following followed by System adj.[10]: 1. Transmission Circuit 2. Transformer [6]	Loss of one of the following: 1. Transmission Circuit 2. Transformer [6] 3. Shunt Device [7]	3Ø	EHV, HV	Yes	Yes

singles)	3. Shunt Device [7] 4. Single pole of a DC line	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 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

Steady State & Stability

For all Extreme Events evaluated:

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

Steady State

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:
    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:
    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.

Stability

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:
    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. 3Ø fault on two or more circuits on a common structure[12].
    g. SLG fault on all Transmission lines on a common 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). 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.
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 (IPO) breaker,

Table 1 — Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
only one pole is assumed to remain closed. A stuck breaker introduces a delayed clearing mode. 12. Excludes circuits that share a common structure 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