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.

Proposed Action Plan and Description of Current Draft:

The SDT has established an aggressive schedule of meetings and conference calls that allows for steady progress through the standards development process in anticipation of completing their assignment in 2Q08. The current draft is the first 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. Violation Risk Factors, Time Horizons, Measures, Compliance and Implementation Plans will be included in subsequent postings.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Respond to comments from first posting of standard(s) and submit revision 1 of the standard(s).	4Q2007
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q2007
3. Submit revision 3 of the standard(s) for balloting.	4Q2007
4. Submit standard(s) for recirculation balloting.	2Q2008
5. Submit standard(s) to BOT.	2Q2008
6.	
7.	

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.

Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect Facility Ratings.

Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

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

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

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

Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, 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.

Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.

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

Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.

System Stability Study: Study of the System or portions of the System to ensure that 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 studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies.

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 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.

   4.1.3. Resource Planner.

   4.1.4. Load-Serving Entity.

   4.1.5. Transmission Owner.

   4.1.6. Generator Owner.

5. **Effective Date:** TBD

B. Requirements

R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R1.1. Load forecasts adhering, at a minimum, to the following criteria:

R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads.

R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility.

R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements.

R1.2. Load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements.

R1.3. Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority.

R1.4. Known planned outages and long-term outages for Transmission and generation equipment including protective relays with consideration given to spare equipment strategy.

R1.5. Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies.

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

R2.1. The steady state portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period and be supported at a minimum by the following annual current studies,, supplemented with qualified past studies as shown in Requirement R2.6:

R2.1.1. System peak Load for either Year One or year two, and 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 Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation with the rationale for the selected sensitivity(ies) shall be supplied:

R.2.1.3.1. Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.

R.2.1.3.2. Modification of expected transfers.

R.2.1.3.3. Unavailability of long lead time facilities.

R.2.1.3.4. Variability and outages of reactive resources.

R.2.1.3.5. Generation additions, retirements, or other dispatch scenarios.

R.2.1.3.6. Decreased effectiveness of controllable Loads and Demand Side Management.

R.2.1.3.7. Modification of planned Transmission outages.

R2.2. For the steady state portion of the Long-Term Transmission Planning Horizon Planning Assessment, 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 portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.3.1. A current study shall be performed if changes in the BES result in increased fault currents such as resource additions and other Facility changes that result in reductions in impedance.

R2.4. The System Stability portion of the Near-Term Transmission Planning Horizon Planning Assessment shall address all five years of the assessment period, 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, the Load model shall include the dynamic effects of induction motor Loads.

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

R2.4.3. Sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run with documentation provided explaining the rationale for the selected sensitivity(ies):

R.2.4.3.1. Variations in Load model assumptions.
R.2.4.3.2. Expected simultaneous transfers including non-firm transfers.
R.2.4.3.3. Unavailability of long lead time facilities.
R.2.4.3.4. Reactive dispatch of generators and other reactive power devices.
R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R2.5. The plant Stability portion of the Planning Assessment shall be analyzed consistent with Requirement R4.6 with studies for the year when the following occur:

R2.5.1. New generator(s) are added or generation modifications are made such as increasing generation capability, replacing the exciter or addition of a power System stabilizer.

R2.5.2. Material changes in the electrical vicinity of existing generation are made such as the addition or removal of a Transmission Line at or near the point of Interconnection.

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

R2.6.1. For steady state analysis: if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes.

R2.6.2. For short circuit analysis: if the study is less than five years old and no material changes have occurred to the System in the intervening period.

R2.6.3. For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.

R2.7. 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, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements in the tables. Such plans shall:

R2.7.1. Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.

R.2.7.1.1. 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. For the Long-Term Transmission Planning Horizon, provide an in-service year..

R2.7.2. Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables.

R2.7.3. Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'

R2.7.4. Not remove committed projects without documentation to show that the revised plan meets the performance requirements.

R2.7.5. Be reviewed in subsequent annual Planning Assessments as to implementation status of identified System Facilities and Operating Procedures.

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 contingencies in Table 1 – Steady State Performance. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R3.1. Studies shall determine whether the BES meets the performance requirements in Table 1 – Steady State Performance.

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

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

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

R3.3. For Steady State studies:

R3.3.1. Performance criteria for System normal conditions and for Planning Events in Table 1 – Steady State Performance shall be met.

R3.3.2. Evaluations shall be performed for single Contingencies (identified in Table 1 – Steady State Performance).

R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.

R.3.3.2.2. Following single Contingency events, System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.

R3.3.3. 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, evaluated for System performance, 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.

R3.4. Those Extreme Events in Table 1 – Steady State Performance that are expected to produce more severe System impacts shall be identified, evaluated for System performance, 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. If the Extreme Events analysis concludes there are Cascading Outages caused by the occurrence of Extreme Events, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R3.5. Manual and automatic generation run-back is allowed as a response to single and multiple Contingencies as long as Facility Ratings are not exceeded.

R3.6. Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions:

R3.6.1. TBD

Note: WECC has informed the SDT that it will be submitting an Interconnection-wide regional variance to allow for manual and automatic generation tripping for single Contingencies. The regional variance will be justified based on physical System differences in the western Interconnection. WECC is developing a white paper to support this position. The actual text of the regional variance will be included in the next posting of this standard.

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 – Stability Performance. The studies shall cover both System Stability and plant Stability. The following requirements apply to both System Stability and plant Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R4.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R4.2. Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention.

R4.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R4.4. Studies shall identify any planned upgrades (including protection and control modifications) needed to meet the performance requirements of the Planning Events of Table 2 – Stability Performance and validate their effectiveness.

R4.5. For the System Stability study:

R4.5.1. At a minimum, those Planning Event Contingencies in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, and 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.

R4.5.2. At a minimum, those Extreme Events in Table 2 – Stability Performance that would produce more severe System impacts shall be identified, evaluated for System performance, 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. If the Extreme Events analysis concludes there are Cascading Outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

R4.6. For the Plant Stability studies:

R4.6.1. 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.

R4.6.2. 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.

R4.6.3. 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. The identified Contingencies, at a minimum, shall be evaluated.

R4.6.4. Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance.

R5. 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] [Time Horizon: TBD]*

R6. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among affected entities, coordinating analysis of these results through an open and transparent peer review process. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

R6.1. Transmission Planners within the Planning Coordinator's area

R6.2. Transmission Planners of neighboring impacted areas

R6.3. Planning Coordinators of neighboring areas

Table 1 – Steady State Performance

Performance Requirements

For all Planning Events:

- Equipment Ratings shall not be exceeded.
- System steady state voltages and post-transient voltage deviation shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive.)
- Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
- Consequential Load loss is allowed for all cases shown.
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

Planning Events

#	Event	Interruption of Firm Transfer Allowed (does not result in loss of Load)	Non-Consequential Load Loss Allowed
P1 (single Contingency)	Loss of: 1. A generator 2. A Transmission circuit 3. A transformer 4. A shunt device (including FACTS devices)	No	No
P2 (single Contingency)	Loss of: 1. Bus section above 300 kV 2. Non-bus tie breaker (above 300 kV) due to internal fault 3. Single pole of a DC line	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P3 (multiple Contingency)	Loss of either a generator, Transmission circuit, a transformer with low side voltage rating above 300 kV, or a bus and a stuck non-bus tie breaker (above 300 kV)	Yes, if transfer is dependent on the outaged DC line No otherwise	No
P4 (multiple Contingency)	1. Loss of a generator followed by a System adjustment followed by the loss of a generator. 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line 3. Loss of a generator followed by a System adjustment followed by the loss of a Transmission circuit 4. Loss of a generator followed by a System adjustment followed by the	Yes, if transfer is dependent on the outaged DC line No otherwise	No

	loss of a transformer		
P5 (multiple Contingency)	Above 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer with low side voltage rating above 300 kV 3. A transformer with low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer	Yes	No
P6 (single Contingency)	Loss of: 1. A bus tie breaker due to internal fault 2. A bipolar DC line or an asynchronous tie line 3. A non-bus tie breaker (below 300 kV) due to internal fault 4. A bus section below 300 kV	Yes	Yes
P7 (multiple Contingency)	Loss of: 1. A bus section above 300 kV and a stuck bus tie breaker 2. Either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes	Yes
P8 (multiple Contingency)	Below 300 kV, the loss of: 1. A Transmission circuit followed by a System adjustment followed by the loss of another Transmission circuit 2. A Transmission circuit followed by a System adjustment followed by the loss of a transformer 3. A transformer followed by a System adjustment followed by the loss of another transformer	Yes	Yes
P9 (multiple Contingency)	1. Loss of any two circuits on a common structure (excluding where multiple circuits share a common structure for no more than one mile) 2. Loss of a generator followed by a System adjustment followed by the loss of a monopolar or bipolar DC line, or an asynchronous tie line 3. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a second DC line (monopolar or bipolar) or asynchronous tie 4. Loss of a DC line (monopolar or bipolar) or asynchronous tie followed by a System adjustment followed by the loss of a Transmission circuit	Yes	Yes

	5. Loss of a transformer followed by a System adjustment followed by the loss of a DC line (monopolar or bipolar) or asynchronous tie line 6. Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer		

Extreme Events

Evaluation Requirements

For all Extreme Events:

1. See Requirement R3.4
2. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
3. Simulate Normal Clearing unless otherwise specified.

Extreme Event Descriptions

1. Loss of a single generator, Transmission circuit, DC line, or transformer forced out of service followed by another single generator, Transmission circuit, DC line, or transformer forced out of service prior to System adjustments.

2. Local area events affecting the Transmission System such as:
   a. Loss of tower line with three or more circuits
   b. Loss of all Transmission lines on a common right-of-way
   c. Loss of 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 such as:
   a. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation
   b. A successful cyber attack
   c. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation
   d. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes
   e. Regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation
   f. Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes such as problems with similarly designed plants
   g. The loss of older Transmission lines which may not be constructed to meet an entity’s present radial ice or wind loading requirements, while the newer or stronger Transmission lines remain in service
   h. Other events based upon operating experience

Table 2 – Stability Performance Table

Performance Requirements			
For all Planning Events: • The System shall be stable[1] • Dynamic voltages shall be within acceptable limits established by the Planning Coordinator or Transmission Planner (if more restrictive) • Uncontrolled islanding and Cascading Outages shall not occur • Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency. • Simulate Normal Clearing unless otherwise specified.			
Planning Events			
#	**Initial Condition**	**Event**	**Non-Consequential Load Loss Allowed**
P1 (single Contingency)	System normal	Single Line Ground (SLG) fault on, a 3-Phase (3Ø) fault on, or an unexpected loss without a fault of (whichever is worst): 1. A generator 2. A Transmission circuit 3. A transformer	No
P2 (single Contingency)	System normal	1. SLG fault on bus section above 300 kV 2. SLG internal fault in non-bus tie breaker (above 300 kV) 3. A single pole block of a DC line	No
P3 (multiple Contingency)	System normal	SLG fault on either a generator, Transmission circuit, a transformer, or a bus and a stuck[2] non-bus tie breaker (above 300 kV)	No
P4 (multiple Contingency)	A single generator out of service followed by System adjustments	1. Apply a P1.1 Contingency. 2. Apply a P2.3 Contingency. 3. Apply a P1.2 Contingency. 4. Apply a P1.3 Contingency.	No
P5 (multiple Contingency)	A Transmission circuit above 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency.	No

	A transformer with low side voltage rating above 300 kV out of service followed by System adjustments	3. Apply a P1.3 Contingency.	
P6 (single Contingency)	System normal	1. SLG internal fault in bus tie breaker 2. A bipolar block of a DC line 3. SLG internal fault in non-bus tie breaker (below 300 kV) 4. SLG fault on bus section (below 300 kV)	Yes
P7 (multiple Contingency)	System normal	1. SLG fault on a bus section above 300 kV and a stuck bus tie breaker 2. SLG fault on either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (below 300 kV)	Yes
P8 (multiple Contingency)	A Transmission circuit below 300 kV out of service followed by System adjustments A transformer with low side voltage rating below 300 kV out of service followed by System adjustments	1. Apply a P1.2 Contingency. 2. Apply a P1.3 Contingency. 3. Apply a P1.3 Contingency.	Yes
P9 (multiple Contingency)	System normal A single generator out of service followed by System adjustments A DC circuit out of service followed by	1. SLG fault on each circuit of any two circuits on a common structure (excluding events where multiple circuits share a common structure for no more than one mile). 2. Apply a P6.2 Contingency. 3. Apply a P2.3 Contingency. 4. Apply a P1.2 Contingency.	Yes

	System adjustments A transformer out of service followed by System adjustments A spare transformer inserted to replace an outaged transformer followed by System adjustments	 5. Apply a P2.3 Contingency. 6. Apply a P1.3 Contingency.	
Extreme Events			

Evaluation Requirements

For all Extreme Events:

- See Requirement R4.5.2 in the text
- Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each Contingency.
- Simulate Normal Clearing unless otherwise specified.

1. 3Ø fault on generator with stuck breaker
2. 3Ø fault on Transmission circuit with stuck breaker
3. 3Ø fault on transformer with stuck breaker
4. 3Ø fault on bus section with stuck breaker
5. 3Ø internal fault in breaker
6. 3Ø fault on two or more circuits on a common structure
7. SLG or 3Ø fault on all Transmission lines on a common right-of-way
8. 3Ø fault on switching station or substation (loss of one voltage level plus transformers)
9. 3Ø fault with loss of all generating units at a station

Notes:

1. System stable means:
   a. Angular stability:
      i. For Planning Events P1 and P3.2: 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 Scheme is not considered pulling out of synchronism.
      ii. For all other Planning Events: No generating unit or units totaling more than the contingency reserve (spinning reserve) of the Balancing Authority shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection 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.

iii. For all Planning Events: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator or Transmission Planner (if more restrictive).

b. General: Unplanned islanding of portions of the system shall not occur for Planning Events.

2. 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, only one pole is assumed to remain closed.

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

1. WECC Interconnection-wide waiver is under development (see Requirement R3.6.2).

Version History

Version	Date	Action	Change Tracking
1		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