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 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. 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).	2Q08
2. Respond to comments from second posting of standard(s) and submit revision 2 of the standard(s).	4Q08
3. Submit revision 3 of the standard(s) for balloting.	2Q09
4. Respond to comments from third posting and submit revision 3 of the standard.	3Q09
5. Submit standard(s) for recirculation balloting.	4Q09
6. Submit standard(s) to BOT.	1Q10
7. Submit to regulatory authorities for approval.	1Q10

Definitions of Terms Used in Standard

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

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

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

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

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

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

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

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

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

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

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

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. Distribution Provider.

   4.1.5. Transmission Owner.

   4.1.6. Generator Owner.

5. **Effective Date:** As per Implementation Plan (to be supplied later).

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 provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R1.1. The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.

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 Generating Unit Stability. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

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

R2.1.1. System peak Load for either Year One or year two, and 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 of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R.2.1.3.1. Higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day.

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.

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

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

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

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

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.

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

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R.2.4.3.1. Variations in Load model assumptions.

R.2.4.3.2. Modification of expected transfers.

R.2.4.3.3. Unavailability of long lead time Facilities.

R.2.4.3.4. Variability and outages of reactive resources.

R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios.

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and the Planning Assessment shall include documentation of the technical rationale for why each was selected shall be supplied.

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

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

R2.5.2. Material Transmission System changes are made at or near the point of Interconnection of existing Generation such as the removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant.

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

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

R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study 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.

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 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. The Corrective Action Plan shall:

R2.7.1. 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 such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

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

R2.7.3. 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, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.3.3. 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/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met:

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

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

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

R5. 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 be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R5.1. Studies to meet the performance requirements in Table 2 – Stability Performance shall use computer Stability simulations that analyze the response of the BES.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R5.3. Studies shall consider the voltage ride through capability of all generators and identify how the generators are treated in the simulation.

R5.4. For the System Stability study:

R5.4.1. 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.

R5.4.2. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.

R5.4.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R.5.4.3.1. All Facilities shall be operating within their Facility Ratings.

R.5.4.3.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

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

R5.4.4. 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.

R5.5. For the Generating Unit Stability studies:

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

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

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

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

R6. Each Transmission Planner and Planning Coordinator shall define and document the proxies used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R7. 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]*

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. *[Violation Risk Factor: TBD] [Time Horizon: TBD]* This distribution shall include:

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

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information. *[Violation Risk Factor: TBD] [Time Horizon: TBD]*

Table 1 – Steady State Performance

1. Facility Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.
2. System steady state voltages and post-transient voltage deviations shall be within acceptable limits as established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Voltage instability, cascading outages, and uncontrolled islanding shall not occur.
4. Consequential Load and consequential generation loss is allowed for all events shown.
5. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
6. Simulate Normal Clearing unless otherwise specified.

Planning Events

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

P2 Single Contingency	Normal System	Loss of one of the following: 1. Breaker(s) opening without a Fault resulting in a single ended line	X	X	No	No
		2. Bus section	X		No	No
				X	Yes	Yes
		3. Internal Breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. Internal Breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	Loss of one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker)[1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
		6. Stuck breaker (bus tie) attempting to clear a Fault on the associated bus	X	X	Yes	Yes
P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing a Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes

P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	Loss of one of the following: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	X	X	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	1. Loss of any two Transmission circuits on a common structure. (Excludes circuits that share a common structure for 1 mile or less.) 2. Loss of a bipolar DC line	X	X	Yes	Yes

Extreme Events

Evaluation Requirements

For all Extreme Events evaluated:

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 a tower line with three or more circuits.
    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. Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:
        i. Wildfires.
        ii. Severe weather, e.g., hurricanes, tornadoes, etc.
    c. Other events based upon operating experience such as:
        i. Consideration of initiating events that experience suggests may result in wide area disturbances.

Notes

1. 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. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also

isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.

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 Non-Consequential Load.
3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
4. Requirements which are applicable to shunt devices also apply to FACTS devices.
5. 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.

Table 2 – Stability Performance

1. The System shall remain stable. [5]
2. Dynamic voltages shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).
3. Cascading outages and uncontrolled islanding shall not occur.
4. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event.
5. Simulate Normal Clearing unless otherwise specified.

Planning Events

Category	Initial System Conditions	Event [3]	BES Elements out of Service [2, 3]		Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
			(A) > 300 KV	(B) <= 300 KV		
P1 Single Contingency	Normal System	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P2 Single Contingency	Normal System	1. Breaker(s) opening without a Fault resulting in a single ended line	X	X	No	No
		2. SLG Fault on bus section	X		No	No
				X	Yes	Yes
		3. SLG internal breaker Fault (non-bus-tie)	X		No	No
				X	Yes	Yes
		4. SLG internal breaker Fault (bus tie)	X	X	Yes	Yes
P3 Multiple Contingency (Generator + 1)	Loss of a generator followed by System adjustments	SLG or 3-phase Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Single pole of a DC line	X	X	No Yes, if transfer is dependent on the outaged DC line.	No

P4 Multiple Contingency (Fault plus stuck breaker) [1]	Normal System	Stuck breaker (non-bus-tie) attempting to clear a SLG Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
		6. Stuck breaker (bus tie) attempting to clear an SLG Fault on the associated bus	X	X	Yes	Yes

P5 Multiple Contingency (Fault plus Protection System failure)	Normal System	Loss of multiple elements due to a single component failure within a Protection System associated with clearing an SLG Fault on one of the following: 1. Generator 2. Transmission circuit 3. Transformer 4. Shunt device 5. Bus section	X		No	No
				X	Yes	Yes
P6 Multiple Contingency (Two overlapping single Contingencies)	Loss of one of the following, followed by System adjustments: 1. Transmission circuit 2. Transformer 3. Single pole of a DC line 4. Shunt device	SLG or 3-phase Fault on one of the following: 1. Transmission circuit 2. Transformer 3. Shunt device 4. Loss of single pole of a DC line	X	X	Yes	Yes

P7 Multiple Contingency (Common structure)	Normal System	1. SLG Fault on each circuit of any two Transmission circuits on a common structure (Excludes circuits that share a common structure for one mile or less) 2. Loss of a bipolar DC line	X	X	Yes	Yes

Extreme Events

Evaluation Requirements

For all Extreme Events evaluated:

1. See Requirement R5.5.4.
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. With an initial condition of a single generator, Transmission circuit, DC line, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, DC line, 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 or a protection system failure due to a single component failure within the protection system.
    b. 3Ø fault on transmission circuit with stuck breaker or a protection system failure due to a single component failure within the protection system.
    c. 3Ø fault on transformer with stuck breaker or a protection system failure due to a single component failure within the protection system.

d. 3Ø fault on bus section with stuck breaker or a protection system failure due to a single component failure within the protection system.

e. 3Ø internal breaker fault.

f. 3Ø fault on two or more circuits on a common structure.

g. SLG or 3Ø 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.

Notes

1. 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. The stuck breaker event introduces a delayed clearing mode. Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed Protection Systems and breakers. Breaker failure relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker failure relaying will also isolate a predetermined portion of the electric System to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component or breaker that prevents the fault from clearing normally.
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 Non-Consequential Load.
3. For transformer outage events, the reference voltage applies to the low-side winding (excluding tertiary windings) and excluding generator step-up transformers. For generator outage events, the reference voltage apply to the BES connected voltage (high-side of GSU transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
4. 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.
5. 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 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).

C. Measures

M1. To be supplied at a later date.

E. Regional Variances

None.

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