Guidelines for Planning The Southern Company Electric Transmission System

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ASSOCIATED NERC STANDARD(S):
TPL-001-5 (referred to as TPL-001 in this document)

IMPLEMENTATION:
In effect when approved.

Phase in of individual TPL-001 requirements will be based on the effective dates as defined in TPL-001.

July 1, 2023 - Version 5 changes

PURPOSE

The purpose of this document is to provide an overview of general transmission planning philosophies and objectives for planning the Southern Companies' ("Southern") Bulk Electric System (BES), and to document how Southern addresses each requirement of the NERC Reliability Standard TPL-001. This guideline documents the study requirements and the associated BES performance criteria that form the basis for the Planning Assessment, which covers the Near-Term (years 1-5) and Long-Term (years 6-10) Transmission Planning Horizons. The Planning Assessment covers a broad range of system conditions and Contingency events as defined in TPL-001 Table 1 (see Attachment A).

This guideline addresses the steady state and stability topics of TPL-001. The short circuit topics of TPL-001 are addressed in a separate document entitled "Guidelines for System Modeling and Short Circuit Assessment of Southern Electric Transmission System."

The "Transmission Planning Philosophy and Objectives" section below is intended to assist in understanding high-level planning objectives and to provide context regarding transmission planning at Southern. Sections 1 through 8, which correspond to the requirements R1 through R8 in the NERC Reliability Standard TPL-001, provide general technical guidelines for Transmission Planners in meeting the reliability requirements of TPL-001. Each section is organized starting with the NERC TPL-001 requirements being provided in a Gray box, followed by guidance on approaches to meeting the requirement.

The intent of these guidelines is to help the planner or other interested reader more fully understand the philosophies behind the planning processes, and the approaches applied in meeting the planning requirements. The background transmission planning information provided herein is not intended to conflict with or circumvent any requirements in NERC TPL-001, nor should any passages be inferred to remove or increase compliance obligations under the NERC Reliability Standards, or any other applicable state or federal laws or regulations. In any cases where a reader might infer a potential conflict, the governing provision is the NERC TPL-001 requirement.

Transmission Planning Philosophy and Objectives

Before discussing how the reliability requirements of NERC TPL-001 are addressed, which will be covered in detail in Sections 1 through 8, it is helpful to better understand several areas of focus for planning transmission in the Southern BES, and the reasoning behind them. A primary responsibility of transmission planning for Southern is to comprehensively assess how to provide for reliable future system operations, including understanding how physical, economic, and regulatory factors may affect how power system facilities operate. The following discussion is intended to help increase understanding of why transmission planning for the Southern BES has a proactive, long-term focus on physical delivery capability, and how doing so helps reduce uncertainties, supports transmission customers in their decisions, and enables more cost-effective solutions and system operations.

Fully Meet Reliability Requirements

The goal of Southern in the transmission planning process is to provide transmission customers safe, reliable, and affordable delivery from their resource choices to their customer loads through dependable long-term firm physical transmission service. Long-term firm transmission service in Southern is considered physical in that cost-effective options are identified to create sufficient physical transmission capacity to enable reliable physical delivery of the transmission customer's service under a wide range of system conditions. Securing long-term firm physical transmission service provides customers delivery priority throughout the year with the intent that their service will rarely be interrupted or curtailed. With this goal in mind, it is Southern's intent to fully meet or exceed NERC and SERC reliability requirements and related reliability criteria applicable to transmission planning.

Support Flexible, Reliable, and Resilient Operations

One of the goals of transmission planning is to minimize challenges in the operating environment, to the extent practical, by identifying potential operating constraints and mitigations in advance and planning a transmission system which reliably supports transmission customers' needs. Transmission planning coordinates closely with system operators to review actual, stressed system conditions as well as anticipated future conditions to reflect them in transmission models. The transmission planning process considers both the reliability requirements of the NERC planning standards and the broader scope of operational implications such as impacts on operating reserves, regulation/ramping needs, power quality, resiliency, restoration capabilities, and other operational needs. Examples include:

- Ability to economically dispatch network resources and other firm physical transmission service under alternate system conditions
- Ability to perform maintenance and restoration activities
- Ability to reliably mitigate stressed system and potentially recurring operating conditions identified by system operators
- Operational impacts of variable energy resources
- Operating implications of changes to firm network generation facilities, coordinating with resource planners and generator operators to understand, model, and assess:
    - Firmness of fuel supplies and capabilities of backup fuel storage
    - How environmental constraints may impact plant performance
    - Nuclear offsite power and coordination requirements
    - Outage stability limits related to maintenance activities
    - Impacts on system resiliency and restoration/blackstart capabilities
- Impacts to operating reserve requirements
    - Generation additions/changes are assessed and configured such that a single contingency will not disconnect more generation than the loss of the largest single unit within Southern

(currently ~1300 MWs). Similarly, proposed HVAC or HVDC interfaces are also assessed for potential impacts to reserve levels.

- Impacts to Southern and neighboring transmission systems, as well as Southern's ability to serve customer demand, as a result of extreme events. Extreme events include outages of several bulk electric facilities such as the loss of multiple transmission lines utilizing common towers or rights-of-way, loss of all generating units at a plant, or the loss of a substation.

In support of future system operations, Southern seeks to ensure that transmission system performance remains reliable, robust, and resilient to address both normal and severe operating conditions and events. To address the uncertainties inherent in transmission planning inputs (such as load forecasts, resource changes, variable generation, and fuel forecasts), Southern assesses long-term firm physical delivery service needs and identifies cost-effective transmission expansion options considering a wide range of scenarios and operating conditions, providing not only a degree of margin in ensuring compliance with all applicable reliability standards, but also providing necessary operational flexibility in economically accessing firm network generation resources, scheduling maintenance/construction activities, and responding to significant system events.

<u>Long-term Focus on reducing resource uncertainties, costs, and delivery risks</u>
Transmission planning at Southern has a long-term focus aimed at minimizing delivery risks and delivery cost uncertainties for long-term firm transmission customers. Long-term firm, physical transmission service enables transmission customers to dependably meet their current and future customer obligations through securing delivery service priority provided at predictable costs. Transmission service requests and commitments made by transmission customers for long-term firm, physical transmission service result in removing resource uncertainties from the planning process and enable transmission planners in assessing their transmission customers' specific delivery needs, thereby providing lead-time to identify and implement reliable and cost-effective delivery options.

The Southern affiliated Operating Companies (OPCO) have "Duty to Serve" obligations that require them to ensure adequate and reliable energy supplies at just and reasonable rates for both their current and future customer loads. The OPCOs in the Southern Balancing Authority Area (SBAA) strive to meet their "Duty to Serve" obligations through procuring generating capacity on a least total-cost basis, which includes the consideration of transmission delivery costs and the lead times required to implement any required transmission expansion.

The Southern transmission planning process enables and encourages Load Serving Entities (LSEs) to designate sufficient network resources to serve their forecasted network loads on a long-term firm basis throughout a ten-year planning horizon and beyond. LSEs and other transmission customers have the opportunity to develop generating resources (or alternately, to procure Power Purchase Agreements) by having access to the transmission delivery cost implications of their decisions, and the ability to secure priority firm physical transmission service to ensure reliable and affordable delivery during the life of their assets or agreements. At times when resource decisions may not yet be known or finalized (typically later in the planning horizon), LSEs may provide native load reservations for future resources as inputs into the transmission planning process. However, to receive firm service, LSEs must make transmission delivery commitments (designations) early enough to enable all required transmission expansion projects to be completed prior to or coincident with the commencement of the desired delivery service from the designated resources. In this way, most transmission delivery commitments within the 1-5 year planning horizon are known, supporting sufficient lead-times for constructing transmission enhancements. Transmission enhancements for point-to-point transmission customers are also assessed, in a comparable manner, and completed (in most cases) commensurate with their delivery needs. Transmission planning is open and transparent with transmission reservations and studies being available through the Open Access Same-time Information System (OASIS).

Reliable, Firm, Physical Transmission Service

Southern seeks to ensure that long-term firm, physical transmission service is reliable (and rarely subjected to curtailments) enabling transmission customers to mitigate both delivery risks and delivery cost exposure in their resource decisions. The transmission planning approach to providing firm, physical transmission service is to meet reliability requirements and maintain the ability of long-term firm transmission customers to operate their resources across a range of system conditions. For example, the reliability impacts of system contingencies (such as the loss of any line or transformer coupled with the loss of a generating unit) are addressed in a manner which does not rely upon curtailing generation with firm transmission service or shedding firm load. Additionally, analysis is performed to ensure that generation resources with firm transmission service can reliably run at firm contractual levels. Through ensuring adequate physical capacity is in place to meet long-term firm delivery needs, transmission customers receive highly dependable, physical delivery service with rare curtailments.

Economic Timing of Transmission Expansion Projects in Corrective Action Plans

Transmission planning for Southern is a highly iterative and continuous process to accommodate potentially changing inputs. Transmission expansion plans are not a blueprint, but rather provide a snapshot of the currently identified project solutions and timing. Transmission expansion plans are continuously reassessed and revised to reflect updated load forecasts, resource changes, new firm delivery service or reliability requirements, new public policy requirements, new solution options, and other drivers. Southern strives to identify the most cost-effective options for meeting reliability and delivery service requirements and strives to implement them to coincide with the timing of the transmission delivery service need.

In continually seeking to minimize costs to transmission customers, transmission expansion projects which are not in a construction stage are reassessed each year. Expansion projects may be deferred or removed if the reliability need is delayed or goes away. Expansion projects may be replaced if more economic solutions are identified. Expansion projects may need to be advanced if the reliability need is advanced. By timing completion to coincide with delivery service needs, transmission customers are able to commence their delivery service when requested, benefit from more cost-effective solutions that may arise during the interim and avoid premature carrying costs.

Table of Contents

This guideline is organized in a format similar to the NERC TPL-001 standard. The text in shaded grey boxes is taken from the NERC standard. The standard requirement topics are generally organized as follows:

Guideline

1.0 R1 – Model Requirements

> R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

Southern Company Services Transmission's (SCST) Transmission Planning department maintains Transmission system modeling data for the SBAA in a database which is typically used to build up to a 10-year planning horizon series of base case system models. The resulting models are used by Transmission Planning for steady state analysis studies and are the basis for stability study model development. The model data is consistent with the requirements of the NERC MOD-032-1 standard. The planning base case models contain the most recent as-built system data plus the most recent projected Corrective Action Plan (CAP) projects and therefore represent the projected system conditions. Transmission Planning base case models are developed utilizing input from modeling processes of applicable entities including the Eastern Interconnection Reliability Assessment Group (ERAG), SERC Long-Term Working Group (LTWG), and Florida Reliability Coordinating Council (FRCC).

Transmission base case models are developed or modified at least on an annual basis to reflect the most current information and assumptions available concerning the modeling of the system in future years.

The system dynamic models for the Southeastern sub-region of SERC are based on the same steady state system models with the addition of machine dynamic model data provided in accordance with MOD-032-1. Machine dynamic data have been collected from all existing generators on the system. As-built machine dynamic data are required from every interconnecting generator prior to commercial operation. Machine dynamic data for forecasted machines in the Long-Term Transmission Planning Horizon may not be available from the Generator Owner (GO). In those cases, dynamic data is assumed based on a similar machine type and is updated as provided by the GO.

1.1. System models shall represent:

1.1.1. Existing Facilities

1.1.2. New planned Facilities and changes to existing Facilities

1.1.3. Real and reactive Load forecasts

1.1.4. Known commitments for Firm Transmission Service and Interchange

1.1.5. Resources (supply or demand side) required for Load

The system modeling process includes representation of:

1.1.1 Existing generation and Transmission facilities based on the most recent as-built data provided by the Generation Owner (GO) or the Transmission Owner (TO).

1.1.2 The Transmission system topology, including projects in the most recent CAP and other expected Transmission improvements for the Near-Term and Long-Term planning horizons. The current forecasts of generation expansion or resource plans are provided by all Load Serving Entities (LSE's) and Network Integration Transmission Service (NITS) customers.

1.1.3 Real load forecast is obtained from the LSE's latest forecast and from all NITS customers for peak and relevant Off-Peak conditions. Reactive load forecast is based on field measured data of the existing system which is extrapolated with a constant power factor for future planning horizon years. Specific future loads such as new or expanding large industrial customer loads (real and reactive) are modeled based upon the best available data.

1.1.4 Known Firm Transmission Service Commitments.
The interchange between external systems is based on the most current external system models provided from interconnection-wide and regional data bank models such as the ERAG's Multiregional Modeling Working Group (MMWG) or SERC's LTWG. Additional modeling updates obtained from neighboring utilities and/or other modeling coordination processes may also be used.

1.1.5 Generation resource assumptions within the SBAA are based on the latest information provided by the LSEs and NITS customers as well as Firm Transmission Service Agreements (TSAs) out of the SBAA. In addition, generators with approved Firm TSAs into the SBAA are typically modeled on-line at the TSA output level consistent with 1.1.5. The TSA amounts are coordinated with neighboring utilities through SERC's LTWG and other modeling coordination processes.

2.0 R2 – Annual Planning Assessment and Corrective Action Plan

> 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 qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

SCST Transmission Planning, as the Planning Coordinator for each of the OPCO's, prepares an annual 10-year Transmission Planning Assessment and corresponding CAP.

Steady State: The steady state analysis to support each OPCO's portion of the Southern Company Planning Assessment is prepared annually, references the applicable studies which have been performed, and contains the Near-Term and Long-Term horizon CAP for meeting the TPL-001 requirements. The steady state assessment covers evaluation of thermal loading of facilities and bus voltages after incorporation of the CAP required to meet TPL-001 Table 1 performance criteria. The assessment documents the study assumptions and summarizes study results validating the CAP. Furthermore, the Southern Company consolidated steady state analysis Planning Assessment consolidates the CAPs of all three transmission-owning Operating Companies. The CAP also includes the Georgia Integrated Transmission System (ITS) participants' transmission system plans.

Stability: The stability portion of the Planning Assessment is prepared annually and references the applicable studies which have been performed. This portion of the assessment documents the assumptions and summarizes the results of the stability analyses. The studies are used to develop recommendations involving relay schemes, breaker specifications or requirements, System Operating Limits (SOL's), and system improvements. The recommendations made are included in the stability portion of the CAP.

> 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6.

Steady State: The Planning Assessment is based on annual studies which are performed for each of the Southern Company OPCOs covering each year of the Near-Term Planning Horizon. These studies consider TPL-001 Table 1 Category P0-P7 Planning Events and Extreme Events. The results demonstrate that required performance criteria are met based on the Transmission Planner's CAP for each OPCO. This CAP is reassessed each year to confirm continued need, timing, and scope until projects have transitioned from planning to a construction stage. These reassessments also investigate potential need for additional mitigating actions or modification to projects currently included in the CAP. The CAP considers and reflects the respective lead times to complete any identified Transmission projects.

Qualifying studies need to include the following conditions:

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

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

2.1.1 – System peak loading models representing summer loading conditions are developed and studied for each of the five years in the Near-Term Transmission Planning Horizon.

2.1.2 – System Off-Peak loading models representing approximately 70% of the summer peak loading are developed and studied for at least one of the five years in the Near-Term Transmission Planning Horizon.

System base case models are considered starting points for Peak Demand and Off-Peak evaluations. The CAP is developed based on these System models and analyzed against a range of assumption sensitivities such as those listed in R2.1.4 for Peak Demand and Off-Peak conditions. The Planning Assessment will document the sensitivity study assumptions evaluated in the planning studies.

Generating resources are modeled in the base cases to meet forecasted loads. In Near-Term Transmission Planning Horizon models, available generation is typically known. In Long-Term Transmission Planning Horizon models, LSEs may include forecasted generation to meet their forecasted load growth. Consideration should be given to whether forecasted generation should be relocated in the model for local area planning to avoid an unintended positive or negative impact on analysis results.

Qualifying studies need to include the following conditions:

2.1.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

TP/PC Technical Rationale and Process for Known Outages - In the SBAA, most outages for system additions and maintenance are taken in the Spring and Fall times of the year due to the lower load levels and availability of generation for redispatch. Each outage goes through a review and scheduling process to ensure that system reliability is maintained. The outages of more concern for inclusion in steady-state planning assessments for the SBAA in the Near-Term Planning Horizon are those that are expected to occur during the Summer and Winter peak seasons when system load is much higher and fewer resources exist for use in generation redispatch. It is outages that occur during these higher load level periods that need to be evaluated for inclusion in system steady-state assessments per the standard.

To accomplish this, outages which are known to be required during these periods will be reviewed for inclusion in the Near-Term Planning Horizon system analysis. For the SBAA, known outages are defined as:

1. An outage that is planned and scheduled in the Near-Term Planning Horizon, including those with some level of schedule uncertainty.
2. An outage that is the result of equipment that has been damaged and where the equipment is projected to be out of service for an extended period of time.

For the SBAA, outage coordination is a continuous process with outages being evaluated and added to the known SBAA outages throughout the year. A request for a list of outages that are known, at the time of the request, will be sent at least annually to the SCS Bulk Power Operations Department. The list received from the SCS Bulk Power Operations Department will be the outages considered for inclusion in Near-Term Planning Horizon steady-state assessment. This list can be augmented with outages from TOs which meet the criteria, but which were not included in the official outage list obtained from the Bulk Power Operations Department. Once the list is received from SCS Bulk Power Operations, Southern Company Transmission Planning will evaluate the outages in the area to determine if based on timing, location, and duration the outage should be included in cases or should be included in the assessment. In the SBAA, duration will never be the sole reason for exclusion of an outage for inclusion in the model. The review will include determining what Facilities will be taken out of service in the model especially when multiple sections of a breaker-to-breaker line are included. Once the outages have been reviewed and selected for inclusion, a review with the Reliability Coordinator (RC) and/or their staff will take place to ensure the RC is in agreement that the most limiting system conditions will be included in steady-state planning assessments.

Assessments are performed for known outages on peak and near-peak planning models for the P0 and P1 (known outage plus additional single contingency) planning events as described in R3.4 with contingencies evaluated per R3.3.

> Qualifying studies need to include the following conditions:
>
> 2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The Transmission equipment sparing strategy will be reviewed annually to identify Transmission equipment with a manufacturing or replacement lead time greater than one year. During system studies, if any long lead time Transmission equipment (one year or more) is identified that does not have a spare, then its unavailability will be modeled and evaluated with P0, P1, P2 events considered in the Near-Term Transmission Planning Horizon.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Steady State: Annual planning studies are performed for TPL-001 Table 1 P0, P1, and P3 category planning events for each year in the Long-Term Transmission Planning Horizon. P2, P4-P7, and Extreme Events are evaluated for at least one year of the five-year Long-Term Transmission Planning Horizon. The rationale for selecting the year to study is discussed as a part of the report documentation.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Short Circuit: Addressed in "Guidelines for System Modeling and Short Circuit Assessment of Southern Electric Transmission System."

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

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

The stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon is prepared annually and utilizes the applicable current or past studies which have been performed.

Stability studies are generally performed for two system load levels –Summer Peak Demand and 50% of Summer Peak Demand (Off-Peak load).

2.4.1 The annual Peak Demand case studied is generally chosen to be a later year in the Near-Term Transmission Planning Horizon because System load tends to increase with time in the planning models. The annual Peak Demand cases include a dynamic load model which represents the effects of induction motors.

2.4.2 The Off-Peak case with load levels 50% of the Summer Peak Demand is modeled for an early year in the Near-Term Transmission Planning Horizon.

2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Stability base case models are considered as starting points for system evaluations. The CAP is developed based on these system models and analyzed against one or more of the assumption sensitivities listed above.

2.4.4. When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. This assessment shall include, at a minimum, those known outages expected to produce more severe System impacts on the Planning Coordinator or Transmission Planner's portion of the BES. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

TP/PC Technical Rationale and Process for Known Outages: In the SBA, most outages for system additions and maintenance are taken in the Spring and Fall times of the year due to the lower load levels and availability of generation for redispatch. Each outage goes through a review and scheduling process to ensure that system reliability is maintained. The outages of more concern for inclusion in stability planning assessments for the SBA in the Near-Term Planning Horizon are those that are expected to occur during the Summer and Winter peak seasons when system load is much higher and fewer resources exist for use in generation redispatch or during Spring and Fall seasons at light load levels. It is outages that occur during these load levels that need to be evaluated for inclusion in system stability assessments per the standard. To accomplish this, outages which are known to be required during these periods will be reviewed for inclusion in the Near-Term Planning Horizon system stability analysis. For the SBA, known outages are defined as:

1. An outage that is planned and scheduled in the Near-Term Planning Horizon, including those with some level of schedule uncertainty.
2. An outage that is the result of equipment that has been damaged and where the equipment is projected to be out of service for an extended period of time.

For the SBA, outage coordination is a continuous process with outages being evaluated and added to the known SBA outages throughout the year. A request for a list of outages that are known, at the time of the request, will be sent at least annually to the SCS Bulk Power Operations Department. The list received from the SCS Bulk Power Operations Department will be the outages considered for inclusion in Near-Term Planning Horizon stability assessment. This list can be augmented with outages from TOs which meet the criteria, but which were not included in the official outage list obtained from the Bulk Power Operations Department. Once the list is received from SCS Bulk Power Operations, Southern Company Transmission Planning will evaluate the outages in the area to determine if based on timing, location, and duration the outage should be included in in the assessment. In the SBA, duration will never be the sole reason for exclusion of an outage for inclusion in the model. The review will include determining what Facilities will be taken out of service in the model especially when multiple sections of a breaker-to-breaker line are included. Once the outages have been reviewed and selected for inclusion, a review with the Reliability Coordinator (RC) and/or their staff will take place to ensure the RC is in agreement that the most limiting system conditions will be included in stability planning assessments.

Assessments are performed for known outages on peak and near-peak planning models for the P1 (known outage plus additional single contingency) planning events as described in R4.4 with contingencies evaluated per R4.3.

> 2.4.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

The Transmission equipment sparing strategy will be reviewed annually to identify Transmission equipment with a manufacturing or replacement lead time greater than one year. During system studies, if any long lead time Transmission equipment (one year or more) is identified that does not have a spare, then its unavailability will be modeled and evaluated with P0, P1, P2 events considered in the Near-Term Transmission Planning Horizon.

> 2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part 2.6 and shall include documentation to support the technical rationale for determining material changes.

Stability: A stability assessment is made for the Long-Term Transmission Planning Horizon for known generation additions or changes. This assessment may utilize applicable current or past studies which have been performed.

> 2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
>
> 2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.
>
> 2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

Steady state: Steady state analysis for the Near-Term and Long-Term Transmission Planning Horizon is typically performed annually and therefore use of past studies under R2.6 would not normally apply. However, in situations where qualifying past studies are still deemed appropriate under 2.6, then the required supporting technical rationale will be provided with the Planning Assessment.

Stability: Qualifying past studies will be used along with current studies for the stability assessment. When past studies are used, documentation will be included with the Planning Assessment showing that no material changes have occurred in the system which would affect the results of the study. Also, when past studies are more than five calendar years old, a technical rationale will be provided to show why the study is still valid.

Short Circuit: Addressed in “Guidelines for System Modeling and Short Circuit Assessment of Southern Electric Transmission System.”

> 2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3.

Steady state: The Planning Assessment is based on annual studies of TPL-001 Table 1 performance requirements. The CAP is summarized in an attachment to the annual Planning Assessment.

Stability: The stability portion of the Planning Assessment is based on current and past studies which have been performed. These studies are used to develop recommendations involving relay schemes, breakers, stability limits, and system improvements. The recommendations made are included in the CAP.

> The Corrective Action Plan(s) shall:
>
> 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:
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> - Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
> - Installation, modification, or removal of Protection Systems or Remedial Action Schemes
> - 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.

The annual planning process includes simulation of each of the planning events of TPL-001 Table 1. In cases where the existing Transmission system does not meet the TPL-001 Table 1 performance requirements, a CAP will be developed that includes combinations of operating guides and Transmission expansion projects. In cases where operating guides are used to meet system performance requirements, those guides are provided to Transmission Operations for review at least annually as part of the planning process.

Each year the CAP from the previous year is reevaluated based on any known or forecasted system changes (including modification or retirement of Transmission or generation Facilities) and updated as needed. The annual Transmission planning study is the evaluation of the most recent CAP's ability to meet the performance requirements of TPL-001 Table 1.

> 2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

Transmission enhancements recommended as part of the CAP are based on the 10-year planning horizon base cases that represent the latest load and generation forecasts provided by the LSEs and NITS customers. The effectiveness of the CAP will be evaluated against future sensitivities as described in R2.1.4 and R2.4.3. If the CAP is found to not address performance requirements for multiple future sensitivities, then the proposed CAP solutions would be re-evaluated considering factors such as operational flexibility. An explanation will be provided in the Planning Assessment if the CAP is not modified to address performance deficiencies observed in multiple sensitivity studies.

> 2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

In some cases, unexpected system changes may occur beyond the control of the Transmission Planner or Planning Coordinator which prevent the planned implementation of a CAP or result in the CAP not achieving the intended results. In such cases, if a revised CAP cannot be implemented in the required timeframe, the Transmission Planner will document the actions being taken to correct the situation. During the transition, the Transmission Planner will identify and document the situation which caused the problem, the options evaluated to address it, and whether non-consequential load loss or curtailment of Firm Transmission Service are being utilized during the interim until a permanent solution is in place. In addition to the near-term actions being taken to mitigate the reliability constraint, the CAP will also be updated to document the expected in-service date of CAP items needed to resolve the situation without relying upon non-consequential load loss or curtailments.

> 2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The CAP is reviewed and updated annually and as needed. Operating guides are provided to Transmission Operations (including the RC) for review to ensure validity as needed. The CAP will contain the implementation status.

> 2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:
>
> 2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.
>
> 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

Short Circuit: Addressed in “Guidelines for System Modeling and Short Circuit Assessment of Southern Electric Transmission System.”

3.0 R3 – Steady State Studies

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

Steady state: The Transmission Planner and Planning Coordinator perform studies for the Near-Term and Long-Term Transmission Planning Horizons per Requirement R2, Parts 2.1, and 2.2, respectively. These studies are based on computer simulation models that are updated annually using data provided per Requirement R1.

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

Steady state: System studies are performed for each category of planning events of TPL-001 Table 1 as described in R3.4 with contingencies evaluated per R3.3.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

Steady state: The extreme events described in R3.5 are modeled based on knowledge of the System.

Post extreme event simulations are reviewed to determine if they result in:

- Loss of substantial customer demand (generally exceeding loss of 300MW of total load), or
- Cascading outage of Transmission Facilities (per the criteria in R6), or
- The inability of a portion of the balancing area to reach a stable post-event operating point, or
- Potential impacts beyond the SBAA into neighboring Systems.

Extreme events with significant potential impacts will be reviewed and options to mitigate the impacts identified. CAP recommendations will consider the probability of occurrence, severity of potential impacts, and the associated costs.

> 3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:
>
> 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> 3.3.1.1. Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.
>
> 3.3.1.2. Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.1 - Contingencies are evaluated on the transmission system to simulate a post-fault clearing steady state case consistent with protective device operation.

3.3.1.1 - Generators in the SBAA are generally modeled explicitly including their step-up transformers. The model includes generator reactive limits and generator terminal voltage limits which have been provided by GOs. Terminal voltage limits, including voltage limits due to station service, are based on a coordinated study with generating plant owners/operators. Generators in the model are generally set to regulate the high side bus voltage to a scheduled value without violating the generator reactive limits. If the generator reactive capability is not sufficient to maintain the high side bus voltage, the generator is fixed at its reactive power absorption or production limit in the simulation solution. Planners monitor the generator terminal voltage in their studies to ensure the voltages are within the acceptable range provided by the GO. If the generator terminal voltage is outside the acceptable range, either the generator terminal voltage limit must be addressed or the generator must be assumed to trip as a result of the initiating Contingency.

3.3.1.2 - The evaluation of Transmission Facility tripping based on relay loadability will be initially performed with a conservative screening process. If the screening process indicates potential relay operation, then a detailed review will be conducted based on actual relay settings.

Transmission lines

For transmission lines 230 kV and above, contingency case line loading results are screened against 150% of the maximum continuous Facility Rating (typically Winter Rate A) and where exceeded are evaluated against actual relay setting.

For all transmission lines below 230 kV, contingency case line loading results are screened against 125% of the maximum continuous Facility Rating (typically Winter Rate A) and where exceeded are evaluated against actual relay setting.

Autotransformers

500/230 kV, 230/161 kV or 230/115 kV autotransformer contingency case transformer branch loading results are screened against 125% of the maximum continuous Facility nameplate rating (typically Winter Rate A), and where exceeded, are evaluated against actual relay setting.

If the screening results exceed the conservative limits:

- Request the actual Zone 3 or transformer overload relay trip settings for the Facility in question.

- If the contingency loading exceeds the actual Zone 3 or transformer overload settings, determine the proper corrective action.

For events where subsequent Facility tripping (cascading) is not allowable P0 – P7, the corrective action items could include allowable modification to relay settings or schemes, or other solutions including System modifications.

For extreme events where subsequent Facility tripping is allowed, corrective actions similar to P0 - P7 events may be evaluated, or the opening of the line or transformer branch may be evaluated per R3.5.

In either case, when System adjustments or operating guides are used to reduce a Facility loading within an acceptable time, an assessment is performed to ensure that the contingency loading did not exceed overload relay settings to ensure that Facilities do not trip based on relay loadability.

> 3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

In steady state analyses, devices that have automatic operations are modeled in automatic mode, such as load tap changers, switched reactive devices, and continuous reactive devices. Moreover, generators are modeled to maintain scheduled voltages on the transmission system automatically during the simulation.

> 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

The analysis methods used to model the planning events of Table 1 vary by event, therefore an explanation is provided for simulations of each planning event. For most P0-P7 category events, all events in the SBAA meeting the event description are evaluated unless specifically noted in the study. Therefore, a comprehensive "more severe event contingency event list" is not created. For situations where all events are not modeled in the study an explanation is provided in the following discussion for each event category. In all cases, the post-contingency simulation results, branch thermal loadings, and bus voltages are compared to acceptable performance criteria. The planning studies are designed to cover each category of planning event from NERC TPL-001 Table 1 as follows:

P0 - Evaluation of normal System with no Contingency event is achieved with a thermal and voltage limit check of all SBAA BES elements for each study case.

P1 - Evaluation of normal System performance for single Contingency events will be performed to demonstrate the capability of the System without allowing Non-Consequential load loss. In the unlikely event that Non-Consequential load loss is used to address BES performance the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process would be followed.

P1.1 - Evaluation of loss of generation event is performed using a series of base cases where key individual generator units[1] are modeled off-line, and the remaining SBAA generation is re-dispatched to meet SBAA load for each of these generator, off-line contingency (N-G) cases. A list of the key individual generators is provided in the study documentation. The required re-dispatch is based on expected SBAA dispatch order and is performed only to balance SBAA generation with SBAA load, losses and interchange while maintaining appropriate spinning reserves and keeping the analysis' swing machine within its limits.

P1.2 - The simulation software has an automated tool which outages each Transmission circuit branch in the system model one branch at a time. Therefore, a list of Contingencies is not required since all possible SBAA Contingencies are evaluated.

P1.3 - Two-winding transformers are a subset of P1.2 branches. The three-winding transformers in the SBAA receive a special review requiring additional contingency evaluations. A list of three-winding transformers is provided in the study documentation.

P1.4 - Shunt devices which are expected to have a significant impact on the BES are identified based on system knowledge and modeled with a low impedance branch connecting a dedicated shunt bus to the network model bus. This low impedance branch modeling method results in analysis of shunt devices as a subset of P1.2. A list of shunt devices modeled with low impedance connecting branches is provided in the study documentation.

P1.5 - Not applicable. In the Southern Company transmission system, HVDC lines are not currently installed and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

P2.1 - For steady state post-event analysis, this category of event is analyzed as a subset of the P1.2 analysis. In limited circumstances, if Non-Consequential Load Loss were used to address BES performance, the process described in TPL-001 Table 1 footnote 12 and Attachment 1-Stakeholder process will be followed.

P2.2 - Bus section faults are modeled and analyzed based on specific substation bus configurations to provide for the expected operation of system protective devices, including bus differential schemes, due to a single event. P2.2 events involving EHV and HV elements are evaluated according to their applicable Table 1 performance criteria. A list of bus section faults modeled is provided in the study documentation.

- Substations with multiple straight bus sections have each bus in the SBAA modeled discreetly as separate bus nodes simulating Bus-tie breakers. Contingencies are performed to simulate each bus section's bus differential relay operation.
- Substations with a ring bus configuration are typically modeled in base cases as a single node. Detailed substation models are built allowing contingencies to be performed simulating each bus section's line relay operation which opens the ring for evaluation.
- Substations with a breaker and ½ configuration are modeled in most base cases as a single node. Contingency evaluations of bus section outages are not routinely studied since in initial design these substations are planned to allow a main bus out for maintenance. Individual bay section outages resulting in a line open at the substation are evaluated as part of the P2.1 review.

P2.3 - Internal breaker faults (non-Bus-tie Breaker) are simulated by modeling back-up breaker operation on either side of the failed breaker. The EHV and HV BES levels are evaluated

[1] For combined cycle units, individual unit contingencies include the full CT + ST outage.

separately consistent with Table 1 performance criteria. A list of non-bus-tie internal breaker faults modeled is provided in the study documentation.

P2.4 - Internal breaker faults on Bus-tie breakers are simulated by opening all breakers on the buses on either side of the Bus-tie. A list of bus-tie internal breaker faults modeled is provided in the study documentation.

P3 - Individual N-G cases developed for P1.1 category (generator outage) events are the starting point cases for subsequent single Contingency P3 event studies. The re-dispatch required as a result of the assumed generator outage is not performed as a system adjustment for the purpose of addressing System issues resulting from the individual generating unit assumed to be off-line. The system adjustment philosophy is described at the end of this section. In limited circumstances, if Non-Consequential load loss were used to address BES performance, the process described in TPL-001 Table 1 footnote 12 and Attachment 1- Stakeholder process would be followed.

P3.1 - The loss of a P3.1 second generator (N-2G) is generally simulated using the PSS/E contingency analysis feature as the loss of a generator step up (GSU) transformer branch. This occurs automatically since the GSU is modeled explicitly. Combined Cycle (CC) units are generally connected to the System through a single branch and this branch outage in the contingency analysis simulates the total loss of the CC. In addition, N-2G simulations are also performed to evaluate the P3.1 loss of generator event.

P3.2 - P3.4 - Evaluated in the same manner as P1.2 - P1.4 except with the P3 “generator off-line contingency” cases.

P3.5 - Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

P4 - Stuck breaker event analysis, in the post-fault clearing steady state results in the same evaluation as a P2.3 internal breaker failure event.

P4.1- P4.5 - For steady state this event is the same as P2.3.

P4.6 - For steady state this event is the same as P2.4.

P5 - The non-redundant relay schemes are evaluated by simulating the event as described by the Protection and Controls Department as a result of CAPE simulation results.

P6 - System adjustments, as described later in this section, made following the initial condition event in preparation for the P6 event are noted in study results.

P6.1 - P6.3 - The PSS/E simulation software contingency enumeration feature is used to rank all possible SBAA two branch-offline Contingency combinations. The program then solves cases for branch pairs in ranked order based on the defined success cut-off criteria. Shunt devices are modeled and outages simulated as described in P1.4.

P6.4 - Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

P7.1- Outages of two Transmission circuits that share a common tower for greater than one mile are simulated with SME individual contingency files. A list of common tower loss events is provided in the study documentation.

P7.2 - Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

The following two sections detail the use of the terms “system adjustments” and “operating guide” in study methods and documentation.

System Adjustments for Steady State Studies

The concept of a system adjustment is referred to in performance category P3 and P6 requirements of the TPL-001 standard. Typically, the standard is referring to an adjustment during an undefined time period between unrelated contingencies of a multi-Contingency event. The standard allows for system operators to make system adjustments following the initial Contingency event to be prepared for a subsequent Contingency event.

For P3 category initial conditions, following loss of a generator unit, system adjustments may include Transmission switching and allowable generation dispatch adjustments in preparation for an additional P3 contingency event.

For P6 category initial conditions, following the loss of the first Transmission element, system adjustment may include Transmission switching and allowable generation dispatch adjustments in preparation for the outage of the next (second) element.

Extreme Event analysis under R3.2 will require analysis of the system performance assuming system adjustments were not made following the initial P3 or P6 event and prior to the P3 or P6 second contingency event. The following are not classified as system adjustments:

- For P3, the goal of expected system re-dispatch when generation is lost due to contingency is to maintain the load/generation balance and is not made to favorably prepare the system for a subsequent event. Therefore, this re-dispatch is not classified as an intentional system adjustment.
- Other adjustments which occur in a simulation to model automatic equipment operation such as voltage regulator operation, SVC control operation, or switching of shunt reactive devices (based on voltage set points) occurring as designed are not classified as an intentional system adjustment.

Operating Guide

An operating guide is an action performed as a post-contingency Corrective Action to alleviate a thermally overloaded Facility or a Facility with a voltage violation. Those guides meet the following criteria and must be performed within a time duration such that Facility designed maximum operating temperatures are not exceeded.

- Generation dispatch performed to address specific post-contingency voltage or thermal performance requirements is limited to fast start generation (< 15 minutes) or the ramp rate of specific generation. Where dispatch is used as an operating guide, alternatives are evaluated to determine whether the operating guide relies on a single generator, or if similar acceptable post-contingency system results could be achieved with other options allowed by the Standard. In general, operating guides relying upon a redispatch of a single generator option are avoided.
- Transmission configuration changes such as operator controlled switching actions, load transfers, etc. which are performed manually at an operator’s direction to address specific post-contingency voltage or thermal performance requirements must be able to be performed within a time period

such that the Facility does not exceed its designed maximum operating temperature. The amount of time available for post-Contingency operator initiated remedial actions is determined based on the pre-Contingency and post-Contingency Facility loading levels. These two loading levels are inputs to a short-term current carrying capability assessment which estimates the amount of time required for a conductor to reach its rated operating temperature post-Contingency based on its pre-Contingency loading level. Typically, 15 minutes or more are desired when considering post-Contingency remedial actions.

> 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

The PC/TP will coordinate with adjacent system PC/TPs to obtain a list of contingencies on their systems which they have observed may potentially result in reliability impacts on the SBAA System. These contingencies will be evaluated in the same manner as those events identified in R3.4.

The PC/TP will monitor SBAA planning event impacts on Facilities in the adjacent Systems for potential unacceptable performance during R3.1 and R3.2 studies. SBAA Contingencies resulting in potential reliability impacts on adjacent PC/TP facilities will be summarized and provided to those adjacent entities during the annual planning process.

> 3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading 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.

Table 1 Extreme Events evaluations are divided into three categories:

1. Planning Events that were mitigated with specific system adjustments should be evaluated assuming that the system adjustment has not occurred in the planned timeframe.

2. Local area events impacting multiple generation or Transmission facilities.

3. Wide area events impacting generation at two separate stations.

The list of specific contingencies expected to produce more severe impacts will be simulated to cover these Extreme Events. These contingencies will be included in the Planning Assessment as well as the rationale used to identify the contingencies. A study would then be performed under R3.2.

4.0 R4 – Stability Studies

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.1.1 - For normally-cleared, three-phase faults (P1), units will not be allowed to pull out of synchronism nor trip on voltage relay protection. If a unit is determined to pull out of synchronism or trip on voltage relay protection, then a solution to the problem will be included in the stability CAP.

4.1.2 - When generating units become unstable for Planning Events P2 – P7, the apparent impedance swings will be monitored using the generic line relaying model of PSS/E. Impedance swings into the Transmission system which are predicted to trip Transmission system elements indicate unacceptable system performance. If this occurs, a solution will be included in the stability portion of the CAP to prevent the units from becoming unstable.

4.1.3 - The damping of power oscillations will be monitored for the stability simulations. Acceptable damping is considered to be 3% or greater.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. If the analysis concludes there is Cascading 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.

Studies will be performed to assess the impact of extreme events.

> 4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:
>
> 4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
>
> 4.3.1.1. Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
>
> 4.3.1.2. Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.
>
> 4.3.1.3. Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.1 - All stability simulations remove all elements that the protection system and other automatic controls are expected to remove. Where high speed reclosing is used, unsuccessful reclosing will be simulated. Successful high-speed reclosing is typically not simulated as, compared to unsuccessful high-speed reclosing, successful high-speed reclosing is expected to result in the same or less conservative results.

Generators will be tripped in the simulations when GSU high side voltages are outside the generator's known or assumed ride through capability limits.

The generic relay model in PSS/E will be used for all simulations. If a power swing gets into the Zone A relay characteristic or stays in the Zone B characteristic for more than 0.35 seconds for lines other than the faulted element, the actual relay characteristics will be obtained and compared with the swings to see if a Transmission element should be tripped in the simulations.

> 4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall:
>
> 4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.3.2 - The expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities will be simulated when such devices impact the study area. Most of the generator controls will automatically be included in the simulations.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

A list of contingencies which are expected to produce more severe system impacts for planning events will be created for evaluation in the stability studies. The list of contingencies is designed to cover each category of planning events from Table 1 as follows:

P0 - Not applicable to stability

P1.1 - P1.4: A study is conducted which applies a normally cleared, three-phase fault on every line and transformer in the SBAA. These simulations will result in more severe system impacts than faults on generators and shunt reactive devices. Faults on generators will not be as severe because fault clearing will result in tripping a unit which is better for stability. Faults on shunt devices will also not be as severe because tripping a shunt device does not result in weakening the System as compared to tripping Transmission lines.

P1.5 - Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

P2.1 - Opening a line end without a fault will never cause a stability concern that has not already been revealed by faults on the line, as assessed under P1.

P2.2 - P2.4: Planning events P2.2, P2.3, and P2.4 require single line to ground faults to be applied to bus sections or internal to breakers. These will always be less severe than a three-phase fault which will be covered by the extreme events specified in Table 1 Stability events 2.d and 2.e. When the three-phase faults in the extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.

P3 - The initial system condition of a generator out is generally not a stability concern because less generation is better for transient stability. A generator out is only a potential stability concern for peak load levels in FIDVR prone areas.

P4 - Planning events P4.1 through P4.6 require single line to ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a stuck breaker. These will always be less severe than a three-phase fault which will be covered by extreme events specified in Table 1 Stability events 2.a through 2.e. When the three-phase faults in the extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.

P5 - Planning events P5.1 through P5.5 require single-line-to-ground faults to be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections with delayed clearing due to a relay failure. Single line to ground faults will be less severe than a three-phase fault which will be covered by R4.5 extreme events specified in Table 1 Stability events

2.a through 2.e. When the three-phase faults evaluated in the R4.5 extreme events result in instability, a solution will generally be included in the CAP. If situations should occur where the CAP is not used to address three-phase faults which resulted in instability, then the single line to ground fault will be investigated and appropriate corrective action included as needed.

P6.1- P6.3: Studies will be performed with a Transmission element out of service at generating plants on the system. Then a three-phase, normally-cleared fault will be studied on another element at the generating plant. If the generators will not be stable for this contingency, then a system adjustment or a CAP project will be implemented to make sure that the generation will remain stable for the Contingency.

P6.4 - Not applicable as HVDC lines are not currently installed in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

P7.1 - Single-line-to-ground faults will be simulated on two Transmission circuits at a generating plant that share a common tower for greater than one mile. The circuits to be studied will be ones at generating plants which would have more impact on stability.

P7.2 - Not applicable as HVDC lines are not currently utilized in the SBAA System and no HVDC lines outside of the SBAA have been identified as affecting the SBAA System.

System Adjustments for Stability Studies

Typically, the only P3 or P6 system adjustment which is used in stability studies is dispatching down generation to maintain stability for the next contingency. The adjustments are given to Transmission Operations as stability limits. These adjustments are ones that can be made within 30 minutes. These issues are generally found for off-peak conditions where generation is available to make up for the generation reductions. Note that such System Adjustments to dispatch down generation for stability studies as described above should not be considered for nuclear units.

4.4.1 - If any dynamic impacts are found on adjacent systems, the Contingency producing the impacts will be communicated to the Planning Coordinator/Transmission Planner (PC/TP) for that system so they can study the impact to their system. Also, the SBAA PC/TP will coordinate with adjacent system PC/TPs to obtain a list of contingencies on their System which they have observed may potentially result in dynamic impacts on the SBAA System.

> 4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

A list of contingencies which are expected to produce more severe system impacts for extreme events will be created for evaluation in the stability studies. Table 1 Extreme Events evaluations are divided into two categories:

1. Planning events that were mitigated using specific system adjustments (resulting in temporary stability limits). Those adjustments should be assumed not to have occurred. Studies will be made of the consequences of having the next three-phase fault with normal clearing before the system adjustments are made.

2. Three-phase faults with delayed clearing due to a stuck breaker or a relay failure. These contingencies will be applied to generators, Transmission circuits, transformers, shunt devices, and bus sections at or near generating plants. These will have the most severe impact to the stability of the system.

If the analysis concludes there is Cascading 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.

For some Contingencies, primarily three-phase faults with delayed clearing, it may be acceptable for generator units to trip with out-of-step protection. If such is the case, then analysis of the same Contingency with a single-line-to ground fault will be performed and noted in the CAP.

5.0 R5 – Voltage Evaluation Criteria

> R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

The evaluation of power flow steady state voltages and transient voltages (dynamic voltages) are the normal means by which satisfactory voltage performance of the System is determined. System bus voltages must not only be evaluated for normal conditions but also for post-Contingency conditions. System conditions falling within the following performance guidelines will be deemed satisfactory unless tighter guidelines have been identified to accommodate special requirements, including but not limited to governmental regulations, highly voltage-sensitive customer operations, or machine stability limitations.

5.1 Planning Event Acceptable steady state Transmission Voltage Level Ranges and Deviation

Table 5.1 A and related notes provide acceptable performance voltage ranges for the pre-Contingency and post-Contingency bus voltage and voltage deviation for TPL-001 analysis. These voltage ranges and deviations are typically used for all planning analysis as a starting point but select studies may utilize more restrictive limits based on the study purpose.

The steady state voltage deviation shown in Table 5.1 A is defined as the difference between pre-Contingency and post-Contingency bus voltages. In steady-state analysis, acceptable deviation must not result in post-Contingency voltages outside of the acceptable steady state range as shown in Table of 5.1 A. When steady state analysis results in a violation of the prescribed voltage deviation in Table 5.1 A, the Transmission Planner should coordinate a project for inclusion in the CAP.

Table 5.1 A

Planning Event		500 kV Acceptable Voltage Range	500 kV Acceptable Deviation	230 kV through 100 kV Acceptable Voltage Range	230 kV through 100 kV Acceptable Deviation
P0 - No Contingency	Generator High-side Bus(2)	0.98 - 1.075(3)	N/A	0.95 - 1.05(3)	N/A
	Switching Station	0.98 - 1.075	N/A	0.95 - 1.05	N/A
	Load Serving Bus	0.98 - 1.075	N/A	0.95 - 1.05	N/A
P1 - P2 Single Contingency	Generator High-side Bus(2)	0.98 - 1.075(3)	Up to full voltage range (1)	0.95 - 1.05(3)	Up to full voltage range (1)
	Switching Station	0.97 - 1.075	Up to full voltage range	0.92 - 1.05	Up to full voltage range
	Load Serving Bus(3)	0.97 - 1.075	Up to full voltage range	0.92 - 1.05	Up to full voltage range
P3 - Multiple Contingency	Generator High-side Bus(2)	0.98 - 1.075(3)	Up to full voltage range (1)	0.95 - 1.05(3)	Up to full voltage range (1)
	Switching Station	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range
	Load Serving Bus(4)	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range
P4 - P5 Multiple Contingency	Generator High-side Bus(2)	0.98 - 1.075(3)	Up to full voltage range (1)	0.95 - 1.05(3)	Up to full voltage range (1)
	Switching Station	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range
	Load Serving Bus(4)	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range
P6 - P7 Multiple Contingency	Generator High-side Bus(2)	0.98 - 1.075(3)	Up to full voltage range (1)	0.95 - 1.05(3)	Up to full voltage range (1)
	Switching Station	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range
	Load Serving Bus(4)	0.97 - 1.075	Up to full voltage range	0.90 - 1.05	Up to full voltage range

Footnotes:

1) No deviation criteria for Generation high-side buses when generating units are meeting the Southern Company Transmission Policy 9 - Reactive Policy for Generating Facilities Connecting to the Southern Company Transmission System reactive policy.
2) For the purpose of voltage level criteria, the generator transmission high side bus should be treated like a load serving bus for the following conditions:
   a. If no units at a plant are turned on in normal system (no planning contingency in effect) power flow evaluation
   b. If for single unit plants, for a normal system planning contingency that involves the outage of the same aforementioned unit
   c. If a plant has been deemed exempt from the NERC Planning Standards requirement of having to hold a voltage schedule
   d. For low MVA plants (<75 MVA aggregate generation or individual units < 20 MVA) where a plant is defined as one or more units that are on-line in the power flow and are interconnected to the same Transmission bus.
   e. Exceptions may be considered for plants above 75 MVA that cannot hold voltage schedule for some standard planning contingencies, if:
      i. Voltage stability margins are above the minimum 5% threshold and
      ii. Power flow analysis indicates that there are no other voltage violations at any load serving buses
3) See discussion of Generator terminal bus voltage limits in Section 5.2.
4) Stations which become radial as a result of the planning event are screened against the same criteria as the post-Contingency networked buses, but if bus voltage remains above the P0 minimum the voltage is acceptable. Additionally, voltage deviations which result in voltages below the P0 planning event minimum allowable voltage but remains within the allowable P1-P2 voltage range, will be evaluated for known specific customer voltage deviation requirements.

5.2 Generator Terminal Bus Voltage Levels

The voltage at the generator terminal buses should not exceed the maximum or fall below the minimum allowable voltage limits for any steady state conditions, including both system intact and planning event conditions. It is expected that the generator owner will specify equipment such that the voltage limit range for a generator low-side bus is 0.95 – 1.05 pu. However, as determined on a case by case basis, reduced ranges may be required. Generator bus voltages falling below the minimum allowable bus voltage will result in tripping of the unit in the study per R3.3.1.1 and R4.3.1.2.

5.3 Nuclear Plant Off-site Source voltages

NERC NUC-001 requires "*Nuclear Plant Generator Operators and Transmission Entities to coordinate for the purpose of ensuring nuclear plant safe operation and shut down.*" The standard further requires "Agreements" to be established which include Nuclear Plant Interface Requirements (NPIRs). The current NPIRs specify acceptable steady state Transmission bus voltage ranges for unit shut-down conditions assuming one unit is undergoing a design basis accident (e.g., loss of cooling event) plus an unrelated worst-case generation or Transmission Contingency.

5.4 Extreme Event Acceptable steady state Transmission Voltage Level Ranges and Deviation

Extreme event contingencies are screened against the same criteria as the post-Contingency P6 and P7 events. These events are then further evaluated to ensure that no steady state voltage collapse is identified.

5.5 Transient (dynamic) voltage response

Summer Peak Demand load levels: For 115 kV faults (P1-P3), voltages must recover above 80% of the nominal voltage within 2 seconds for networked buses, and no units should trip due to low voltage. For lower probability faults, such as three-phase faults with delayed clearing due to a stuck breaker or a protective relay failure (P4-P7), the following should be satisfied:

(1) All networked Transmission buses should recover to above 80% of the nominal voltage within 4 seconds of the initial fault; and

(2) For the north Georgia area, the East Critical Unit (ECU) point value of units tripped should not exceed the largest ECU point value of the most valuable unit in north Georgia; and

(3) All networked Transmission buses should continue to recover to normal voltages in the dynamic analysis.

Off-Peak load levels: For normally cleared faults (P1-P3), the transient voltage dip at any load bus should not remain below 80% of nominal voltage for more than 40 cycles. This only applies to Off-Peak load levels with a standard load model (ZIP) used for loads.

6.0 R6 – System Instability Evaluation Criteria

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.

Steady State: When performing planning event (or extreme event) assessments, an additional analysis should be performed to simulate potential line opening. If the planning event (or extreme event) results in lines loaded above their relay loadability limits, or voltage instability as indicated by non-convergent study cases, then additional steady state analysis is performed to test for potential cascading.

The check for potential cascading Transmission outages assumes no system operator initiated remedial action load shed occurs.

The steady state analysis test for Cascading Transmission Outages is evaluated as follows:

1. For the planning events (or extreme events) which predict significant impacts as described above, the initiating NERC TPL-001 event is modeled, and results are reviewed. Any post-Contingency loading which exceeds the relay loadability limit of the Facility is simulated as opening.
2. The resulting post-Contingency case is evaluated to determine if any additional relay loadability limits have been exceeded. If so, these lines are also opened as a result of relay operation. This step will be repeated until no lines open due to relay loadability or ten (10) lines have been opened.
3. . Once all facilities are within their relay loadability limits, PSS/E's remedial action activity is initiated to shed load and adjust capacitors to resolve line overloads (based on Summer Rate B) or voltages below 0.90 per unit after a steady state power flow solution is achieved. Upon completion of the remedial action load shed, an evaluation of the number of Transmission facilities opened in the simulation and the extent of the area impacted is conducted.

For the purpose of this steady state assessment, the result will be considered potentially cascading if:

- More than five facilities are eventually simulated as opening successively following the initiating event. or
- The resulting overloaded facilities occur outside of the Southern Balancing Authority Area (SBAA), or
- The study case solution will not converge (solve) due to system conditions such as voltage collapse.

Stability: In addition to the steady state analysis, voltage stability and system angular stability analyses are also conducted.

- Voltage stability analysis is made using P-V curve techniques. Voltage instability is defined as the knee of the P-V curve. The system is planned such that it will operate with 5% or greater margin from the voltage instability point for single element out Contingencies (P1-P2) and for unit out with single element out Contingencies (P3). For lower probability Contingencies (P4-P7), voltage stability margins should be 2.5% or greater from the voltage instability point.
- All angular stability analyses which include a generic line relay model will determine when impedance swings impact line relaying. For impedance swings into the Zone 1 protection defined by the generic

model, it is assumed line relaying will trip the Transmission line. Tripping of three or more Transmission lines in this manner (not including the faulted element) defines cascading for stability analyses. When cascading is detected, a solution will be included in the CAP. If the simulation results in multiple lines being tripped such that an electrical island is created, then this will be considered uncontrolled islanding and a solution will be added to the CAP.

7.0 R7 – Planning Coordination / Transmission Planning Roles and Responsibilities

> R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

For affiliated operating companies in the SBAA, SCST Transmission Planning performs the Planning Coordinator and Transmission Planner (PC/TPs) responsibilities for all TPL-001 requirements except those related to short circuit and breaker duty analysis. PC/TP responsibilities include development of study cases, performing planning studies and summary assessments based on coordinated annual 10-year studies, and coordination of any required CAP projects with the respective Transmission Owners (affiliated and non-affiliated Georgia ITS Participants).

SCST Transmission Planning performs the responsibilities of Planning Coordinator for MEAG per Georgia Power's relationship with MEAG as their contractor for services.

SCS Transmission Planning performs the responsibilities of Planning Coordinator for City of Dalton per Georgia Power's relationship with Dalton Utilities as their Agent.

Short circuit and breaker duty requirements are performed by SCST and OPCO Protection and Control groups. The short circuit requirements of TPL-001 R1, R2.3, R2.6, R2.8, R7 and R8 are provided in "Guidelines for System Modeling and Short Circuit Assessment of Southern Electric Transmission System."

8.0 R8 – Planning Assessment Distribution

> R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.

Studies performed as the basis of the Annual Planning Assessments are generally completed by December 31st of each calendar year. The complete documentation and final Annual Planning Assessments are generally completed by the end of the 1st quarter of each calendar year based on planning studies of the prior year.

- Southern Company will provide its most recent annual Southern Company aggregate Planning Assessment with a summary of the CAP within 90 days of completing the assessment to:
    - Adjacent PC/TPs.
    - Impacted RCs (per IRO-017-1 R3)

Other entities with a valid reliability related need may make a written request through the Southern Company Transmission OASIS site to be provided the most recent Planning Assessment. Within 30 days of this written request, Southern Company will provide its most recent annual Southern Company aggregate Planning Assessment with a summary of the CAP.

In either case, those receiving Planning Assessments will be required to meet Critical Energy Infrastructure Information (CEII) requirements, which can be accessed through the Southern Company OASIS website.

> 8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Southern Company will provide a documented response within 90 days of receipt of documented comments from recipients of our Planning Assessment consistent with TPL-001 R8.

DOCUMENT CHANGE LOG

Version #	Date	Description of Key Change
1	December 31, 2014	Approved
2	January 24, 2017	Minor modifications and clarifications for Off-Peak, Sensitivity, Stability, NRIS, and Voltage sections.
3	December 2, 2020	Modifications to voltage criteria, stability system adjustments, Attachments and other sections to improve documentation of compliance.
3.1	October 27, 2021	Corrections to errors discovered in the document after Version 3 approval.
4	January 27, 2022	Modifications for changes in version 5 of the standard and process updates.